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A techno-institutional perspective

Eid, Cherrelle

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DOCTORAL THESIS
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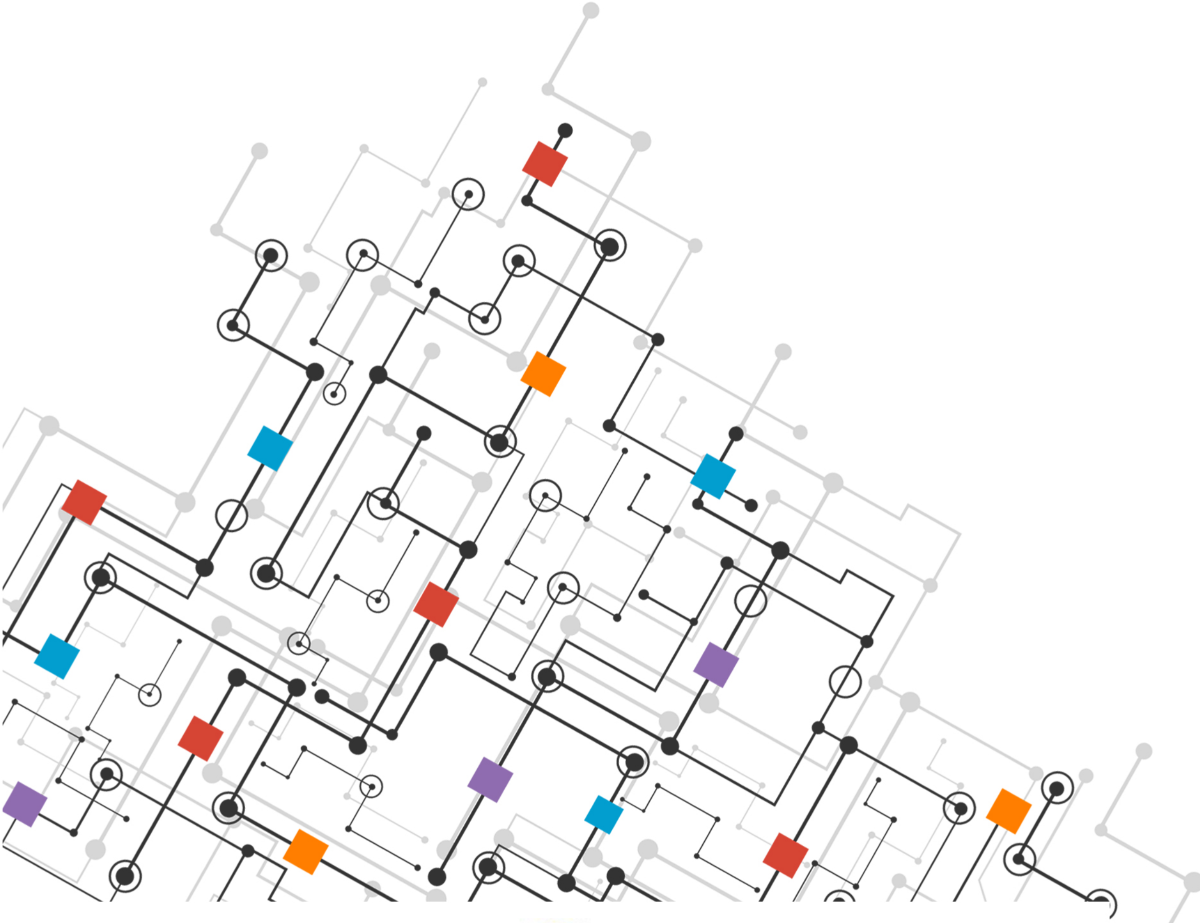
TOWARDS THE DESIGN OF FLEXIBILITY MANAGEMENT IN SMART GRIDS

A TECHNO-INSTITUTIONAL PERSPECTIVE

CHERRELLE EID



Towards the design of flexibility management in smart grids: A techno-institutional perspective

Proefschrift

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aan de Technische Universiteit Delft,
op gezag van de Rector Magnificus prof. ir. K.C.A.M. Luyben,
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door

Cherrelle EID
Master of Science in Economics and Management of Network Industries
Comillas Pontifical Universidad and Université Paris-Sud XI
geboren te Rotterdam, Nederland

This dissertation has been approved by the promotor: Prof. dr. ir. M.P.C. Weijnen and copromotor: Dr. ir. R.A. Hakvoort

Composition of the doctoral committee:

Rector Magnificus	Chairman
Prof. dr. ir. M.P.C. Weijnen	Technische Universiteit Delft, the Netherlands
Dr. ir. R.A. Hakvoort	Technische Universiteit Delft, the Netherlands
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Prof.dr. L. Nordström	KTH Royal Institute of Technology Stockholm, Sweden
Dr. T.W. Fens	Technische Universiteit Delft, the Netherlands

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Cherrelle Eid

Delft, November 2017

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EXECUTIVE SUMMARY

The European policy focus on smart grids implies their development as an indispensable part of the future power system. However, the definition of a smart grid is broad and vague, and the actual implementation of a smart grid can differ significantly depending on the stakeholders involved. Smart electricity grids can be defined as electricity networks that can intelligently integrate the behaviour and actions of all end users connected to them – generators, consumers and those that are both – in order to efficiently ensure a sustainable, economic and secure electricity supply. This integration of behaviour is achieved through a two-way information and power exchange between suppliers and consumers using information technology.

The management of flexibility allows the benefits from smart grids to be made available to the entire electricity value chain. Therefore, the management of electric flexibility in smart grids receives special attention in this thesis. Electric flexibility can be defined as a power adjustment, achieved at a given moment for a given duration, from a specific location within the network. Flexibility management, in this thesis, is the techno-institutional organizational arrangement required to enable the management of electric flexibility at the distribution grid level. The main research question of this thesis is:

"How do the techno-institutional design variables for flexibility management affect the costs and revenues in smart grid systems?"

The thesis also addresses the following sub-questions:

1) What are the techno-institutional design variables for flexibility management in smart grids?
2) How are the techno-institutional design variables for flexibility management applied within traditional and new techno-institutional contexts?
3) What methodology can be used to quantify the costs of flexibility from flexibility-providing units?
4) What are the revenues for trading flexibility from flexibility providing units in existing electricity markets?

Framework for the techno-institutional design of flexibility management

This thesis presents a flexibility management framework for structuring the organizational arrangements required for flexibility management. Flexibility management is the application of four flexibility management design variables – the division of responsibilities (**who**), for the specified management of flexibility of appliances (**what**), by specific means (**how**) and for specific reasons in the system (**why**) – as well as two organizational variables, which are the **number of actors** involved and the **nature of transactions** (See Figure 1).

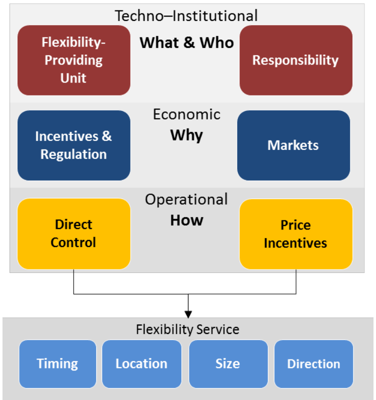

Figure 1: Techno-institutional framework for flexibility management in electricity systems

Technical coordination and economic valuation issues

Using the techno-institutional framework, different organizational models have been identified from smart grid case studies. The case studies illuminate two important issues: the **technical coordination** and **economic valuation** issues. The technical coordination issue refers to the fact that that the network and market needs for flexibility in electricity systems are not naturally aligned and coordinated. This disconnection arises because electricity markets in Europe's power systems are placed centrally within an electricity system (at the wholesale and high voltage level), while network congestions can take place at any line on the distribution and/or transmission network. Therefore, traditional markets do not incorporate location-dependent signals of local networks. Proper technical coordination would support both network capacity and market supply scarcity signals being transferred to the actors in the flexibility management design. This could be achieved through price incentives, regulation or design of new market models.

Economic valuation relates to the issue that electric flexibility will only be activated when it is economically interesting to do so. Flexibility management can be arranged technically in such way that it incorporates both market supply and network capacity scarcity. However, such cases might result in trade-offs with regard to economic viability. Such smart grid projects fundamentally lack a sound business model for flexibility management to operate within the current European regulatory context.

Costs and revenues for flexibility management

The final part of this thesis presents a method for assessing the costs and revenues of flexibility from DERs. The issue of degradation costs is included for battery technologies. The analysis shows that electric vehicles (EVs), in vehicle-to-grid applications, are very expensive for short term flexibility needs in the system (below 30 minutes).

For most technologies, the short-term average costs (STACs) of electric flexibility are significantly higher than the revenues that can be obtained in existing markets such as the day-ahead and balancing markets. The cheapest options from a short-term cost perspective are demand management, flywheel technology and power-to-heat technology. However, when taking account of the trading possibilities in the Dutch balancing markets using data from the year 2016, only the flywheel technology and demand management are economically viable. The results from the analysis of the day-ahead market are negative, as the wholesale prices are too low for distributed electric flexibility to be economically viable.

Demand management

In theory, demand management flexibility could be economically viable for both the end user and the system. If not taking account of the opportunity cost, the cost of reducing demand for a customer is zero, as demand reduction does not involve increased spending by the consumer, but lowers the cost of their electricity bill cost. However, demand management requires further discussion. In reality, there are short-term costs related to demand management, such as the opportunity costs if a specific flexibility-providing unit operated without interruption. An example could be an EV car that is used by a taxi driver to provide battery storage services to the grid, but who would thereby lose the “opportunity” to earn money from providing a transport service to an end user. Other costs related to STACs for demand management could be flexibility-providing, unit-related costs, due to interrupted operations. In short, if the STACs for demand management (which could be the opportunity cost or another flexibility-providing, unit-specific cost) are lower than the retail price of €0.16 per kWh (the average electricity cost per kWh in The Netherlands) or lower than the European average of €0.20 per kWh, and the revenue of performing demand management is higher than these short-term costs, it is economically viable to perform demand management.

In order to ensure coordination of the provided flexibility, it is suggested that the DSO (as an already regulated actor) should be made responsible for ensuring such technical coordination through for example ex-ante presented network tariffs or new market models in which network limitations are already incorporated. To reduce complexity and costs, it is suggested that flexibility management would be a regulatory obligation from certain flexibility-providing units. This could be implemented through an actor, such as the distribution system operator (DSO), or by an independent aggregator. Such an actor would be made responsible for activating this flexibility automatically. The following recommendations are presented for policy makers, aggregators, retailers and DSOs.

Recommendations for policy makers:

1. *Allow flexibility trading by retailers, aggregators and other new parties in existing markets.*

2. *By doing so, create room for business value development for flexibility management.*

3. *Make sure transparent cooperation mechanisms exist between the DSO and the retailers and aggregators.*

4. *Make flexibility obligatory through regulation for specific DERs for managing grid limitations.*

5. *Look beyond smart grids, towards smart energy grids, which include heating networks.*

6. *Adjust the regulation for DSOs, retailers and aggregators according to the new roles given.*

Recommendations for aggregators and retailers:

1. *Investigate possibilities for providing new (flexibility) services*

2. *Join forces with DSOs, local heat providers and other energy counterparties for the provision of new services in markets and/or for other respective stakeholders.*

Recommendations for DSOs:

1. *Investigate the provision of new services beyond electricity network management: experiment beyond the regulated scope.*

2. *Find ways to effectively communicate network limitations to market parties, without conflicting with market activities.*

3. *Investigate the role of data manager while supporting privacy of end users and the free market in the electricity sector.*

4. *Move along with the development of local heat provision and possibly take additional roles in this area.*

5. *Join forces with local heat providers, aggregators and retailers for local sustainability projects.*

Future research: expand data analysis

The quantitative analysis of the costs of the different DERs is based on data published by the US National Renewable Energy Laboratory and the United States Department of Energy. However, most of the data was taken from reports dating from 2010, 2013 and 2015 (see Annex I) and it is expected that the costs of the technologies will already have decreased. It is therefore suggested that future research should analyse the investment costs and STACs using more recent data.

It is also important to state that the cost assumptions for electricity and gas prices and potential revenues were based on data from the Dutch system. The bias towards the Dutch system affected the short-term cost inputs of certain DERs (e.g. solar photovoltaic, gas turbine, micro turbine and power-to-heat technologies). Furthermore, the Dutch prices have been used to calculate the revenues that can be obtained in the Dutch balancing and day-ahead markets. For this research to be extended on a European scale, it is suggested that a larger data set of European market prices for electricity, gas, balancing and day-ahead markets should be included.

It is also suggested that future research analyses the actual costs that are involved with demand management specifically. Besides the technical costs (such as fuel, investments, operation and maintenance (O&M)), there may also be socio-economic costs involved with the activation of flexibility, i.e. the opportunity costs. It would be interesting, in a situation where the technical context is fixed, to analyse the issue of opportunity cost for demand management to show the socio-economic impacts of flexibility management. However, it must be noted that such values of opportunity costs are very situation dependent and could therefore reduce the ability to generalize results.

Further research should also include aspects that make local flexibility-providing units relatively cost comparable with large power generators in central markets. This work presents an initial step towards such cost comparison, but it is important to note that the current price setters in central markets are largely coal, gas and nuclear production units. These units frequently receive government subsidies to cover the large upfront costs, and they are generally not penalized for the externalities that they cause to the environment. Given the large stranded costs in these (inflexible) production units, it is inevitable that the electricity power prices will be low in cases of oversupply, especially with additional inflows from renewable sources with priority access. This aspect of unpredictable inflows from clean renewable sources has not been taken into account in either the market models or the asset base in the sector. As soon as this large asset base reduces its market share, and renewable inflows increase substantially, the need arises for market models that support more real-time demand adjustments, provide priority access to flexibility management (e.g. demand response) and motivate both generation and production to react (close to real time) to the current system status. The author suggests that future research should take account of those aspects that make local flexibility-providing units relatively cost comparable with large power generators in central markets.

Information technology costs and data management organization

Lastly, the costs of IT and data storage are left outside of the analysis in this thesis. It is recommended that future work should include these IT-related costs to provide a complete picture of the costs for flexibility management in smart grids. Furthermore, to effectively develop smart grids, it is important that the responsibilities for data management are well defined and integrated with the techno-institutional design for flexibility management. It is also therefore recommended that the costs for IT and data management should be included.

Future research: multi-energy systems

This work focuses mainly on the issue of flexibility management for the electricity system. However, in addition to electricity, heat, cooling and gas could be included in the design and operation of a smart energy system. Such local energy systems are also the focus of the 2016 Clean Energy Package with local heating and cooling networks for improving energy efficiency and reduction of carbon emissions (European Commission, 2016). Future work could focus on the realization of multi-energy systems in a retail competition context. In such a context, new actors, such as energy service companies, could be providers of energy services and might combine offers for heating, cooling and gas supply for certain urban districts. A topic for future research is how the European retail competition model should be adjusted for service provision that is of a monopolistic nature.

Future research: social aspects

This thesis does not include any analysis of the social aspects of smart grids. However, if flexibility management becomes a market product (which the author believes is the case with an increase in penetration of renewable non-dispatchable electricity sources), it is expected that the market participants (retailers and aggregators) would assume part of the responsibility to find suitable models that benefit society. For successful uptake of flexibility from end users, it is suggested that future research specifically focuses on the techno-institutional design for household appliances only. Due to the specific characteristics of end-user ownership and placement of household appliances, it is recommended that future research therefore distinguishes between two techno-institutional designs; one for household appliances and another for DERs. In this way, future research can help find the most suitable flexibility management approach for different types of flexibility-providing units and end users in the energy sector (electricity, gas, heat and cooling).

Summary in Dutch

De Europese beleidsdruk voor smart grids (intelligente netten) lijkt te impliceren dat de ontwikkeling een onontbeerlijk onderdeel van het toekomstige Europese elektriciteitssysteem zal zijn. De definitie van een smart grid is echter breed en vaag en de daadwerkelijke implementatie ervan hangt sterk af van de betrokken partijen. Smart grids kunnen worden gedefinieerd als elektriciteitsnetwerken die het gedrag en de acties van alle eindverbruikers die ermee verbonden zijn, intelligent kunnen integreren - producenten, consumenten en diegenen die beide zijn - om efficiënt te zorgen voor duurzame, betaalbare en leveringszekere elektriciteitsvoorziening. Deze integratie van het gedrag wordt bereikt door middel van informatie- en stroomuitwisseling tussen leveranciers en consumenten, met behulp van informatietechnologie. Het beheer van flexibiliteit zorgt ervoor dat de voordelen van smart grids beschikbaar worden voor de volledige elektriciteitswaardeketen. Daarom wordt in dit proefschrift bijzondere aandacht besteed aan de management van elektrische flexibiliteit in smart grids. Elektrische flexibiliteit kan worden gedefinieerd als een stroomaanpassing, op een bepaald moment voor een bepaalde duur, vanuit een specifieke locatie binnen het netwerk. Flexibiliteitsmanagement, in dit proefschrift, is de techno-institutionele organisatorische regulering welke nodig is om het beheer van elektrische flexibiliteit op het distributienetwerk mogelijk te maken. De belangrijkste onderzoeksvraag van dit proefschrift is: "Hoe beïnvloeden de techno-institutionele ontwerpvariabelen voor flexibiliteitsmanagement de kosten en opbrengsten in intelligente netwerken?"

Dit proefschrift presenteert een techno-institutioneel raamwerk voor het ontwerp van flexibiliteitsmanagement. Met behulp van het techno-institutionele raamwerk zijn verschillende organisatorische modellen geïdentificeerd uit bestaande smart grid casestudies. De casestudies presenteren twee belangrijke problemen: de technische coördinatie en het economische waarderingsprobleem. Het technische coördinatieprobleem heeft betrekking op hetgeen dat netwerk- en marktbehoeften voor flexibiliteit in elektriciteitssystemen niet vanzelfsprekend op elkaar afgestemd en gecoördineerd zijn. Economische waardering heeft betrekking op het probleem dat elektrische flexibiliteit alleen zal worden geactiveerd wanneer het economisch interessant is om dit te doen.

Het laatste deel van dit proefschrift presenteert een methode om de kosten en baten van flexibiliteit van gedistribueerde energie bronnen (distributed energy resources; DER's) te beoordelen. Voor batterijtechnologieën zijn de degredatie kosten inbegrepen. Uit de analyse blijkt dat elektrische voertuigen te duur zijn voor het leveren van korte-termijn flexibiliteit in het systeem (minder dan 30 minuten). Voor de meeste technologieën zijn de korte-termijn gemiddelde kosten (short term average costs, STAC's) van elektrische flexibiliteit aanzienlijk hoger dan de opbrengsten die kunnen worden verkregen op bestaande markten, zoals de day-ahead en onbalansmarkten. De goedkoopste opties vanuit een korte termijn kostenperspectief zijn vraagsturing, vliegwieltechnologie en warmte-technologie. Echter, als

rekening wordt gehouden met de handelsmogelijkheden in de Nederlandse onbalansmarkt, zijn alleen de vliegwieltechnologie en vraagsturing economisch interessant.

Vraagsturing vereist echter verdere beschrijving. Vanuit theoretisch oogpunt zijn de kosten om de elektrische vraag te verminderen nul, aangezien dit gewoonlijk lager verbruik van electriciteit betekent met daardoor lagere elektriciteitskosten. In werkelijkheid bestaan er korte-termijn kosten in verband met vraagsturing, zoals de opportuniteitkosten als een specifiek apparaat zonder onderbreking zou functioneren. Kort gezegd kan worden gesteld dat indien de STAC's voor vraagsturing (die ofwel opportuniteitskosten of apparaat specifieke kosten) lager zijn dan de elektriciteitsprijs van € 0,16 per kWh in Nederland (dit is de gemiddelde electriciteitsprijs in Nederland), of lager dan €0.20 per kWh in Europa (dit is de gemiddelde Europese electriciteitsprijs) en de opbrengsten van het leveren van vraagsturing hoger is dan deze prijs, het is economisch interessant zou kunnen zijn om vraagsturing uit te voeren. Aangezien de DSO al een gereguleerde actor is, is de DSO de meest logische kandidaat om verantwoordelijk gesteld te worden voor de technische coordinatie van flexibiliteit in het system. Om extra complexiteit en kosten te verminderen, wordt voorgesteld dat dit vraagsturing via regelgeving verplicht zou kunnen worden gesteld voor bepaalde apparaten. Dit kan geïmplementeerd worden door een actor, zoals de distributie system operator (DSO) of aggregator, die verantwoordelijk is voor het automatiseren van deze flexibiliteit.

Voor toekomstig onderzoek wordt voorgesteld om de data analyse uit te breiden met meer recente bronnen van DER kosten en de kosten van informatietechnologie apparatuur, data management en data-opslag. Bovendien kan het effect van multi-energie opslag (inclusief verwarming, koeling en gas) in het ontwerp en uitvoering van een slimme energiesysteem worden opgenomen. Ten slotte wordt voorgesteld dat toekomstig onderzoek de meest geschikte aanpak zal moeten analyseren voor flexibiliteitsmanagement van verschillende soorten gebruikers in de elektriciteitssector. Een suggestie is, dat het techno-institutionele raamwerk apart zal moeten worden toegepast voor huishoudens specifiek, en apart voor DERs. Als flexibiliteitsmanagement echter een marktproduct wordt (wat de auteur meent dat het geval zal zijn), wordt verwacht dat de marktpartijen (leveranciers en aggregators) een deel van de verantwoordelijkheid zullen nemen om passende modellen te vinden die de maatschappij ten goede komen.

Summary in Swedish

Den europeiska politiken att driva smarta nät verkar innebära att deras utveckling är en oumbärlig del av Europas framtida energisystem. Definitionen av ett smart nät är brett och vagt och det faktiska genomförandet av ett smart nät kan skilja sig väsentligt beroende mellan berörda parter. Smarta nät kan definieras som intelligenta elnät som kan integrera beteende och åtgärder hos alla slutanvändare som är anslutna till dem - generatorer, konsumenter och de som är båda - för att effektivt kunna säkerställa hållbar, ekonomisk och säker elförsörjning. Denna integration av beteende uppnås genom tvåvägsinformation och kraftutbyte mellan leverantörer och konsumenter, med hjälp av informationsteknik. Förvaltningen av flexibiliteten gör att fördelarna med smarta nät kan ställas till förfogande för hela elvärdes-kedjan. Därför får hanteringen av elektrisk flexibilitet i smarta nät speciell uppmärksamhet i denna avhandling. Elektrisk flexibilitet kan definieras som en effektreglering, ihållande vid en given tidpunkt under en viss tid, från en specifik plats inom nätverket. Hantering av flexibilitet i denna avhandling är den teknik-institutionella organisatoriska arrangemang, som krävs för att möjliggöra hanteringen av elektrisk flexibilitet i distributionsnätet. Den huvudsakliga forskningsfrågan i denna avhandling handlar om: *"Hur variablerna för teknik-institutionell utformning kring hanteringen av flexibilitet påverkar kostnaderna och intäkterna i ett smart distributionsnät?"*

Avhandlingen presenterar en ram för flexibilitetshantering för att strukturera de organisatoriska arrangemang som krävs för flexibilitetshantering. Med hjälp av teknik-institutionella ramar har olika organisationsmodeller identifierats i smarta distributionsnätstudier. Fallstudierna belyser två viktiga frågor: den *tekniska samordningen* och *den ekonomisk värderingen*. Frågan om teknisk samordning relaterar till kring *nätverkets* - och *marknadens* behov för flexibilitet i elsystem inte naturligt är justerad och samordnad. Ekonomisk värdering avser frågan om elektrisk flexibilitet endast aktiveras när det är ekonomiskt intressant att göra så.

Den sista delen av denna avhandling presenterar en metod för att bedöma de kostnader och intäkter kring flexibilitet från DERs. För batteriteknik ingår frågan om nedbrytningskostnader. Analysen visar att elbilar är mycket dyra för korta flexibilitetsbehov i systemet (under 30 minuter). För de flesta tekniker är de kortfristiga och genomsnittliga kostnaderna (STAC) för elektrisk flexibilitet betydligt högre än de intäkter som kan erhållas på befintliga marknader, såsom dag- och balansmarknader. De billigaste alternativen från ett kortsiktig kostnadsperspektiv är efterfrågestyrning, svänghjulsteknik och kraftvärme-teknik. Men när man tar hänsyn till handelsmöjligheterna på de nederländska balansmarknaderna med uppgifter från 2016 är endast flyghjulstekniken och efterfråganhanteringen ekonomiskt lönsamma.

Hantering av efterfrågan kräver dock ytterligare diskussion. Ur en teoretisk synvinkel är kostnaden för att minska efterfrågan noll, eftersom efterfrågan inte minskar med ökad konsumtion. I verkligheten finns det kortfristiga kostnader i samband med

efterfrågestyrning, som till exempel alternativkostnader om en viss enhet fungerar utan avbrott. Övriga kostnader relaterade till STAC för efterfrågestyrning kan vara enhetsrelaterade kostnader till följd av avbrutna verksamheter. Kort sagt kan det konstateras att om STAC: erna för efterfrågehantering (vilket kan vara alternativkostnaden eller annan enhetsspecifik kostnad) är lägre än detaljhandelspriset på € 0,16 per kWh, och intäkterna för att hantera efterfrågan är högre än dessa kortsiktiga kostnader, är det ekonomiskt lönsamt att hantera efterfrågan.

För att minska ytterligare komplexitet och kostnad föreslås att denna efterfrågehantering bör vara en lagstadgad skyldighet från vissa enheter. Detta skulle kunna genomföras via en aktör, såsom distributionstoperatörer (DSO) eller aggregator, som ansvarar för att aktivera denna flexibilitet på ett automatiserat sätt. Detta skulle säkerställa teknisk samordning kring flexibilitet men skulle minska de nödvändiga regleringsanpassningarna.

För framtida forskning föreslås det en utökning av dataanalysen för att inkludera nyare källor för DER-kostnader och kostnaderna för IT-utrustning och datalagring. Dessutom kan effekten av multi-energilagring (inklusive uppvärmning, kylning och gas) ingå i utformningen och driften av ett smart energisystem. Slutligen föreslås det att framtida forskning analyserar det lämpligaste sättet för olika typer av användare inom elsektorn. Om flexibilitetshantering blir en marknadsprodukt (som författaren anser är fallet) förväntas dock marknadsaktörerna (återförsäljare och aggregatorer) ta del av ansvaret för att hitta lämpliga modeller som gynnar samhället.

DEFINITION OF TERMS

The key definitions used in this thesis are given below.

- **Demand Response**

Demand response is defined as “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/CEER, 2012, page 8). In this thesis, the focus is on changes in electric usage or production, not only for consumers but also for producers and storage units. Therefore, the term “electric flexibility” is used instead of “demand response”.

- **Flexibility-providing Unit**

A flexibility-providing unit is either a household appliance or distributed energy resource with the ability to provide flexibility to the electricity system.

- **Household Appliances**

Household appliances refer to flexibility-providing units that are traditional household-level devices, such as dishwashers, dryers and washing machines.

- **Electric Flexibility**

Electric flexibility is a power adjustment achieved at a given moment in time, for a given duration, from a specific location within the network. This flexibility is obtained from consumers, producers and those that are both, as a response to price or direct control signals. The activation of electric flexibility receives special attention in this thesis as the use of flexibility allows the benefits from smart grids to be made available to the entire electricity value chain: electricity production, transport and consumption (Conchado et al., 2011).

- **European Retail Competition**

European retail competition refers to the fact that in Europe every end user has retail choice. To enable retail choice, the distribution network operators are unbundled, meaning that their services should be disconnected from electricity supply services. Although the level of retail competition might differ slightly across European countries, the basics of the retail competition model are enforced by the European Commission through the laws on functional and legal unbundling of network operators (CEER, 2013a; Newbery, 2002). Therefore these laws are seen as a condition for the recommendations in this thesis.

- **Institutions**

According to North (1984, p. 97): "*Institutions consist of a set of constraints on behaviour in the form of rules and regulations and finally, in a set of moral, ethical and behavioural norms which define the contours and constrain the way in which the rules and regulations are specified and enforcement is carried out*". In this thesis, institutions are all the rules and (market) arrangements that guide flexibility provision from flexibility-providing units by DSOs, retailers, aggregators and end users.

- **Short-term Average Costs (STACs) of Flexibility**

The STACs are the costs involved with the provision of 1 kWh of flexibility, both upward and downward. The calculation method for these STACs is presented in Chapter 6. These costs disregard the costs of information technologies and data management.

- **Smart Grids**

Smart electricity grids are electricity networks that can intelligently integrate the behaviour and actions of all end users connected to them – generators, consumers and those that are both – in order to efficiently ensure sustainable, economic and secure electricity supply (ETP SmartGrids, 2010). In using the term "smart grid", this thesis focuses mainly on electricity management. Smart grid systems that also incorporate heat and gas networks are not the main topic of the thesis, even though some of the cases do touch upon smart energy systems incorporating more than just electricity management.

- **Techno-institutional Design of Flexibility Management**

The techno-institutional design of flexibility management refers in this thesis to the institutional and technologic arrangements needed to support the provision of electric flexibility from flexibility-providing units in the electricity sector. This arrangement is defined as the application of the four flexibility management variables: 1) the division of responsibilities (who); 2) for management of the flexibility from flexibility-providing units (what); 3) by specific means (how); and 4) for specific time-dependent system purposes (why). There are also two organizational variables: the number of actors involved and the nature of transactions.

This techno-institutional design of flexibility management plays a central role in this thesis as the activation of flexibility depends both on technical abilities of flexibility-providing units and on the existing market models, regulation and stakeholder interests in the electricity sector.

LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
APX	Amsterdam Power Exchange
BRP	balance responsible party
CAES	compressed air energy storage
CAPEX	capital expenses
CEER	Council of European Energy Regulators
CHP	combined heat and power
CPP	critical peak pricing
CSP	Curtailment Service Provider
DER	distributed energy resource
DG	distributed generation
DR	demand response
DS	distribution system
DSO	distribution system operator
EAC	equivalent annual cost
EDF	Electricité de France
EDSO	European Distribution System Operators
ENDEX	European Energy Derivatives Exchange N.V.
ESCO	energy service company
EES	electrochemical energy storage
EU-28	28 Member States of the European Union
EV	electric vehicle
FCR	frequency containment reserve
FRR	frequency restoration reserve
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IFRI	French Institute of International Relations
IIT	Instituto de Investigación Tecnológica
ISO-NE	Independent System Operator New England
IT	information technology
JRC	Joint Research Center
LCOE	levelized cost of energy
LED	light emitting diode
Li-on	Lithium-ion
NaS	sodium sulphur
NEBEF	Notification d'Echange de Blocs d'Effacement (French for: Notification of Exchange of Blocks of Load Shedding)
NPV	net present value

NY-ISO	New York independent system operator
O&M	operation and maintenance
OPEX	operational expenses
PJM	Pennsylvania, New Jersey and Maryland
PMC	Power Matching City
PV	photovoltaic
RES	renewable energy source
ROI	return on investment
RR	replacement reserve
RTP	real-time pricing
SCADA	supervisory control and data acquisition
SO	system operator
STAC	short-term average cost
TOU	time of use
TS	transmission system
TSO	transmission system operator
UK	United Kingdom
US	United States
USEF	Universal Smart Energy Framework

1 Introduction

1.1 The Smart Grid

The transition towards sustainable, secure and affordable electricity supply is driving innovation in the consumption, production and transport of electricity. In the past decade there has been a dash for “smart” in power systems resulting in a consensus that “smart grids” will pave the way for de-carbonization, reliability and economic efficiency in the electricity sector. Europe’s very ambitious sustainability objectives for 2020 and 2030 favour a significant share of electricity being produced from renewable sources (European Commission, 2016, 2014a).

Within Europe’s plans for carbon reduction in the electricity sector, smart grids play an important role along with the deployment of renewable energy resources in the sector. In the Energy Efficiency Directive of 2009, the European Commission set a target for 80% of European households to be equipped with a smart meter by 2020 (Directive 2009/72/EC). The term “smart grid” has been used by the European Commission since it published the report “Electricity Networks of the Future” (European Commission, 2006).

However, the definition of a smart grid is broad and vague, and the actual implementation of a smart grid can differ significantly depending on the stakeholders involved. Smart grids can be defined as electricity networks that can intelligently integrate the behaviour and actions of all end users connected to them – generators, consumers and those that are both – in order to efficiently ensure sustainable, economic and secure electricity supply (ETP SmartGrids, 2010). This integration of behaviour is achieved through two-way information and power exchange between suppliers and consumers using Information technology (IT) (EPA, 2007; JRC and DOE, 2012).

The functionalities of the smart grid are not recently discovered concepts. F.C. Schweppe and collaborators previously described these functions in their report “Homeostatic Control: The Utility/Customer Marketplace for Electric Power” (Schweppe et al., 1981). In this report, Schweppe et al. refer to homeostatic control as a way of maintaining internal equilibrium between electricity supply and demand with the use of economic signalling and information and communication technology. In this definition, the activation of end-user flexibility would be beneficial from a cost-saving and reliability perspective.

1.2 Smart Grids and Flexibility Management

Different researchers acknowledge that the management of electric flexibility makes investments in smart grids worthwhile (Aghaei and Alizadeh, 2013; Faruqui et al., 2010; Geelen et al., 2013). Electric flexibility can be defined as a power adjustment achieved at a given moment, for a given duration, from a specific location within the network. This flexibility results from end-user electricity consumption and production behaviour in response to price or control signals. The activation of electric flexibility receives special attention in this thesis, as electric flexibility offers benefits from smart grids that can be made available to the entire electricity value chain: electricity production, transport and consumption (Conchado et al., 2011). This becomes crucial since investing in smart metering alone would not lead to benefits that can be transferred to all actors in the electricity value chain (Faruqui et al., 2010).

Research provides diverse perspectives on the use of such flexibility within smart grids, ranging from technical to economic aspects. Technical literature shows the smart grid from an engineering perspective, as presented by the founders of the term (Amin and Wollenberg, 2005; Samarakoon et al., 2012). Economic research shows the financial costs and benefits of installing and managing specific technologies across the entire value chain of the electricity sector (Faruqui et al., 2010; Gyamfi et al., 2013; Samarakoon et al., 2012). Techno-economic research presents the highly complex nodal-pricing mechanisms that are possible through the use of real-time metering and response at distribution levels (Li et al., 2015; Sotkiewicz and Vignolo, 2006). However, these techno-economic perspectives on the development of smart grids ignore the institutional aspects of the implementation and upscaling of these smart grid technologies in today's societies (Tabors et al., 2010; Tricoire, 2015). In Europe, the development of smart grids is embedded in the retail competition context; thus smart grids will have to take account of the respective techno-institutional design fitting such a context. The effective design of smart grids is therefore of a technical as well as an institutional nature.

Despite the accumulation of literature in this area, there is a noteworthy absence of research that examines the effects of techno-institutional design on smart grids. The relationship between technical and institutional interactions has already been described by Correljé, Scholten and Künneke, based on the work of Oliver Williamson (Correljé et al., 2014; Künneke, 2008; Scholten and Künneke, 2016; Williamson, 1998). In their framework, technical design is inherently related to the technical aspects of energy systems. Their framework has been applied to guide the debate about roles and responsibilities for actors within the liberalization process of energy markets.

1.3 Research Objective and Questions

This work informs policy makers, the electricity industry and researchers about how to design smart grids that take account of the techno-institutionally embedded nature of interactions in the electricity sector. The thesis aims to complement the mainstream scientific literature on smart grids (including its present focus on technical and economic aspects) with institutional aspects.

The main research question is as follows:
How do the techno-institutional design variables for flexibility management affect the costs and revenues in smart grid systems?

The following sub-questions are defined:

1. ***What are the techno-institutional design variables for flexibility management in smart grids?***

Answering the first research sub-question results in an operational design framework for the techno-institutional design of flexibility management in smart grids. This framework supports the structured analysis of case studies for flexibility management in smart grids. It further helps to structure the discussion about the effects on cost and revenue distribution, due to clear definition of specific design variables that affect costs and revenues. The framework is presented in Chapter 3 of this thesis.

2. ***How are the techno-institutional design variables for flexibility management applied within traditional and new techno-institutional contexts?***

The answer to research sub-question 2 presents an application of the design framework for flexibility management for different types of flexibility management structures. First, Chapter 4 presents the use of flexibility management with centrally managed flexibility, within the traditional techno-institutional contexts. Chapter 5 presents alternative market models to trade electric flexibility between (existing or new) actors in a rather distributed manner.

3. ***What methodology can be used to quantify the costs of flexibility from flexibility-providing units?***

Research sub-question 3 provides an insight into the cost aspects of electric flexibility. More specifically, the answer to this question, in Chapter 6, provides a method for determining the investment and STACs for flexibility from Distributed energy resources (DERs).

4. ***What are the revenues for trading flexibility from flexibility-providing units in existing electricity markets?***

Finally, in research sub-question 4, the revenues are calculated for actors trading electric flexibility from DERs. Chapter 7 provides insights into the revenues that can be obtained if flexibility were to be traded in the balancing and day-ahead markets.

1.4 Research Scope

This research focuses on smart grid development within the European techno-institutional context. Due to the liberalization of the sector, enforced by the European Commission, most of the electricity markets in Europe are designed for retail competition. This is taken as an assumption in the analysis and recommendations of this work (Section 2.6 in Chapter 2 describes this European context). However, this thesis not only provides insights for research and policy in the context of European retail competition, it also provides insights for other electricity market models due to the range of case studies presented within alternative market models.

The thesis also focuses on the activation of flexibility at low voltage electricity levels, rather than at high voltage levels. Generally, large consumers and producers that are directly connected at high voltage levels are already suppliers of flexibility within wholesale markets that allow for such trading. This is not yet the case for most residential consumers and suppliers at low voltage levels. Therefore, with the focus on residential smart grids, this thesis provides a structure for the design process for flexibility management at low voltage levels.

1.4.1 Behavioural effects related to price elasticity and other social aspects

The author acknowledges that individual end users have important decision-making power with regard to the provision of electric flexibility. However, the end user alone is not able to engage in, and not aware of efficient flexibility service provision without the settlement of a specific arrangement for the effective use of flexibility between actors like the distribution system operators (DSOs), retailer and aggregator. Therefore, if the organizational arrangement supports trading of electric flexibility, its uptake can be intensified with social and economic incentives for end users. This work therefore focuses on this first step: the techno-institutional arrangements that are required to settle flexibility management incentives for end users. Examples of these are the settlement of time-based prices or direct control mechanisms. There are different social aspects, among other things, that help explain the amount of electric flexibility that can be attained from the end user. Operational aspects like price elasticity of the end user, transaction costs related to the provision flexibility and adverse issues such as consumption rebound effects have been observed in other scientific works. These aspects are not further analysed in this thesis.

1.4.2 Information technology (IT) data management and privacy

The activation of flexibility in smart grids results in large data sets of end-user consumption and/or production data, which should be managed effectively to ensure efficient activation of flexibility, the privacy of the end user and fair competition between actors in the electricity sector. This data management task could be performed by diverse actors (the DSO, retailer and/or an independent actor) with each impacting aspects such as data accessibility, transaction costs, monopoly power and privacy. There are different methods for safeguarding the privacy of the end user, for arranging the management of data and for regulating the actors that will be involved with sensitive data of end users, but these aspects lie beyond the scope of this work.

1.5 Thesis Structure

This thesis is structured as follows. Chapter 2 presents the relationships between smart grids and flexibility management, and illuminates the reasons why diverse actors can use flexibility for different purposes and how this potentially affects their business models. Chapter 3 introduces the design framework for flexibility management, which is used to structure the case studies presented later in the thesis. Chapters 4 and 5 describe, within the proposed framework, multiple cases of flexibility management in smart grids. Chapters 6 and 7 describe a quantitative analysis for the costs of flexibility from DERs. Lastly, Chapter 8 presents the conclusions and recommendations.

After the conclusions, Chapters 9 to 12 present the papers which have been published in the process of writing this thesis. Chapter 9 presents an analysis of the economic effects of electricity net-metering with solar panels for network cost recovery. Chapter 10 presents an analysis of DERs, and their characteristics and abilities to provide flexibility services to the electricity system. Chapter 11 presents a policy paper with regard to time-based pricing and electricity demand response; this paper has been listed for almost a year as one of the the most-downloaded articles from the Utilities Policy Journal. Finally, Chapter 12 presents a paper that describes different cases of flexibility management and is the backbone of Chapter 7 in this thesis.

2 Flexibility Management within Smart Grids

2.1 What is a Smart Grid?

Smart grids can be defined as electricity networks that intelligently integrate the behaviour and actions of all users and appliances connected to them – generators, consumers and those that are both – in order to efficiently ensure sustainable, affordable and secure electricity supply (ETP SmartGrids, 2010). The integration of behaviour and actions of all users and appliances is enabled through two-way information and power exchange through information and communication technologies (EPA, 2007; JRC and DOE, 2012). Even though this development of integration of information and communication technology can also include smart energy and heat grids, in this thesis the term "smart grid" refers to smart *electricity* grids only.

Technically speaking, it is not straightforward to define whether a grid is "smart" or not. Most electricity systems, at least at high voltage levels, have supervisory control and data acquisition systems in place to sustain reliability of supply in an automated fashion. Traditionally, distribution grids are managed without sensor and control systems in place. Within this thesis, smart grids refer to developments at the distribution (low voltage and medium voltage) side of the electricity system.

The functionalities of the smart grid are not recently discovered concepts. F.C. Schweppe and collaborators previously described these functions in a report entitled "Homeostatic Control: The Utility/Customer Marketplace for Electric Power" (Schweppe et al., 1981). Conceptually, the 1981 report presents a picture where a central marketplace controller is an intermediary platform for the management of local and central systems (see Figure 2.1). In order to manage the customer load, Schweppe et al. describe two forms of load management: direct and indirect control. Direct loads refer to methods by which the utility can directly manage electrical appliances by switching flexibility-providing units on or off. In contrast, indirect methods are economic incentives (for example, a time-based electricity tariff) that can incentivize the network user to consume or produce electricity at specific times.

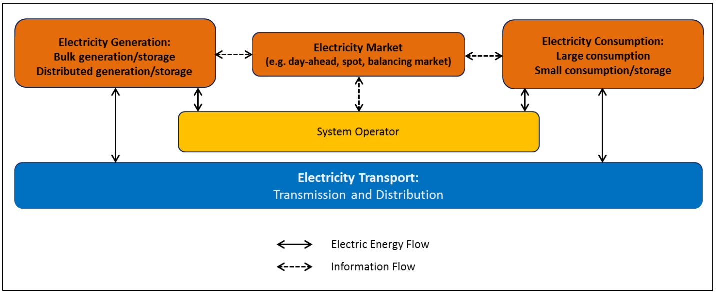

Figure 2.1: Early presentation of the "innovative energy market place" smart grid by Schweppe et al. (1981)

However, the term “smart grid” itself was not used until 2005 when a report from the Institute of Electrical and Electronics Engineers (IEEE) entitled “Toward a Smart Grid: Power Delivery for the 21st Century” was published (Amin and Wollenberg, 2005). In that report, the electric grid is likened to a F15 aircraft with “self-healing” capabilities in case of emergency – similar to Schweppe’s homeostatic description. In this colourful metaphor, the F15 aircraft is able to continue flying due to fault detection and automation even after losing a wing. This use of detection and automation was suggested as a method for improving transmission grid operations.

2.1.1 Typical smart electricity grid components

Smart grids can be simplified by describing them as the incorporation of two elements in electricity distribution, i.e. the installation of physical “smart grid components” and the (close to) real-time management of electric flexibility from those devices (Faruqui et al., 2010; Geelen et al., 2013).

Such smart grid devices involve smart meters and DERs. The smart meter is commonly presented as a prerequisite for smart grids. Unlike in traditional (analog) electricity metering, smart metering allows for digital measurement and wireless communication of measured consumption/production at short time intervals (15 minutes, for example). Smart metering can reduce the costs of electricity metering due to the possibilities of automated and remote data measurement and processing. When combining the smart meter with an in-home energy management system, it is possible for users to manage their electricity demand and to have access to real-time electricity consumption, production and price information (CEER, 2013b). The electricity consumption data can be communicated to different actors – for example, it can be communicated to the consumers themselves (through in-home energy management systems), retailers and/or the DSOs. Furthermore, the smart meter can combine the collection and transfer of other data related to gas, heat and/or water consumption.

Distributed energy resources (DERs) are different types of units that enable local production, time-based consumption and/or storage of electricity (see Figure 2.2). Local production can be provided by distributed generation (DG), such as solar photovoltaics (PV), combined heat and power (CHP) and micro wind power units. Battery storage can provide important value as those units can increase household self-consumption from electricity generation, reduce peak consumption, reduce system-wide generation costs, losses and network congestions, and can reduce costs for network expansion. Electric vehicles (EVs) can be seen as storage units as the batteries can provide flexibility to the grid and, when required, can act as storage units for generated electricity.

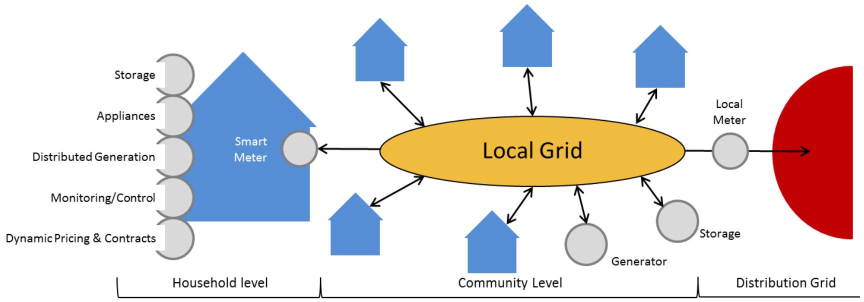

Figure 2.2: Smart appliance categories (from Geelen et al., 2013)

2.2 Definition of Flexibility

The installation of DERs and smart meters alone does not automatically result in efficient interactions between local supply, storage and demand. For this, flexibility management is required through, for example, the settlement of contracts for time-based pricing and direct control of devices (Aghaei and Alizadeh, 2013; Faruqui et al., 2010; Geelen et al., 2013). The flexibility obtained from household appliances or end users is usually categorized in the literature under the term "demand response". Demand response (DR) might give the impression that it is only electricity demand that is eligible to "respond" to triggers like prices or direct control. However, in this thesis, the term "flexibility" refers to the overall responsiveness not just of demand but also of storage and production units. Therefore, the term "electric flexibility" is used instead of "demand response". More technically, electric flexibility can be defined as follows:

Electric flexibility is a power adjustment achieved at a given moment, for a given duration, from a specific location within the network.

The flexibility service can be characterized by five attributes (see Figure 2.3): its *direction* (a); its *electrical composition* in power (b); its *temporal characteristics* defined by its *starting time* (c) and *duration* (d); and its base for *location*. For future anticipated load or decreased production, upward flexibility is required. For future anticipated production or decreased load, downward flexibility is required in the system.

The operation of smart grid components can be optimized for multiple purposes: economic, environmental and network purposes (Conchado et al., 2011). Smart grid assets relate to different technical functionalities, which can provide benefits and costs for (some of the) actors involved depending on how those assets are managed. The benefits of flexibility management are seen as the major added values of the smart grid (Faruqui et al., 2010). A joint report by the Joint Research Center (JRC) and Department of Energy (DOE) presented a list of the most common smart grid assets and their functions as used in the United States (US) and Europe (JRC and DOE, 2012).

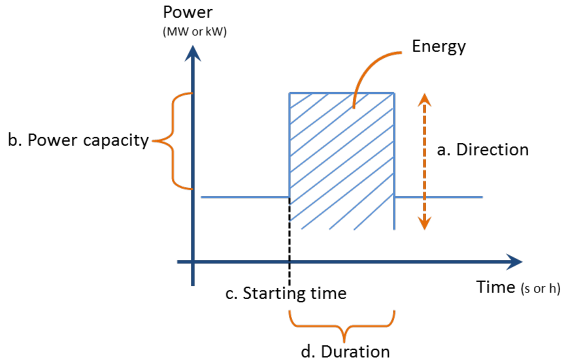

Figure 2.3: The attributes of an electric flexibility service, except for the location (Eid et al., 2015)

This joint report confirms that investments in smart grid assets can simultaneously influence targets related to affordability, sustainability and reliability. For example, distribution automation provides benefits for reliability due to the automated/self-healing ability of the network but can also reduce expenses for network expansion (affordability). At the same time, with excessive penetration of DG units, distribution automation can support reaching sustainability targets. Alternatively, depending on the way in which the time-based tariffs are set up, smart metering with such time-based tariffs can reduce costs for electricity consumers and help support reliability and sustainability objectives. Therefore, depending on the way flexibility management is organized, the flexibility from a similar set of assets can be used for diverse objectives. Due to the large range of flexibility management functions, the smart grid can be seen as a "toolset" for each of the actors involved in the electricity supply chain.

2.3 Traditional View on Flexibility Management

The interactions between actors in the electricity sector are arranged to suit the industry structure in place. In Europe, for example, the electricity sector is based on a retail competition model (see Figure 2.4).

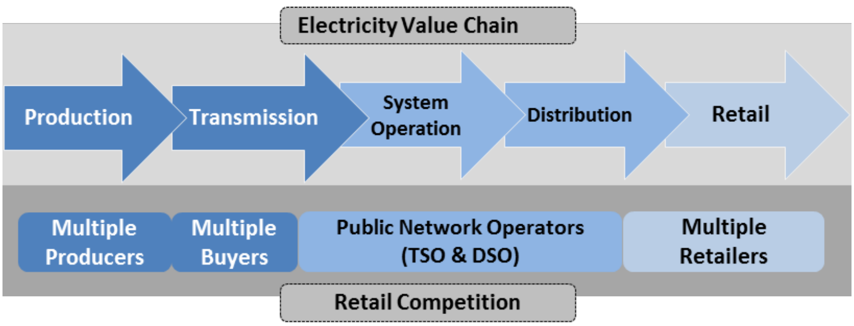

Figure 2.4: Retail competition in the electricity sector, (adapted from Batlle and Ocaña, 2013)

This model refers to the fact that all consumers should be allowed to freely decide which retailer to buy their electricity from. Even though the competition model might be slightly different across countries in Europe, it is enforced by the European Commission through the laws on functional and legal unbundling of network operators (CEER, 2013a; Newbery, 2002). The first European Commission directive enabled the opening up of the electricity market and a gradual introduction of competition, and imposed broad unbundling requirements on integrated companies (Directives 96/92/EC). The Second Energy Legislation Package further focused on the concepts of unbundling and third-party access, and defined the need for independent regulatory authorities (Directive 2003/54/EC and 2003/55/EC). The Third Energy Legislation Package established a new unbundling regime and more clearly defined the duties of national regulatory authorities, including cooperation with the Agency for the Cooperation of Energy Regulators (ACER). It also improved consumers' rights and provided a number of measures for the functioning of the internal electricity market (Florence School of Regulation, 2013). Due to this structure, there are multiple retailers and DSOs involved in smart grid developments.

Traditional electricity systems are managed in a top-down manner, meaning that large generation units connected at high voltage levels feed in electricity for consumers who are located at all other voltage levels. Flexible generation units (mostly hydro, gas and coal-fired power plants) are, as well as being providers of bulk electricity supply, also providers of electric flexibility by means of upward and downward adjustments. These adjustments could be incentivized by, for example, capacity contracts with the system operator (SO) for automatic adjustments. Large (industrial) consumers are already providers of system flexibility in most markets in Europe (SEDC, 2014).

In the US, DR is largely used in many markets, for example, through the Regional Transmission Operator of Pennsylvania, New Jersey and Maryland, known as PJM (PJM, 2014). France and the United Kingdom (UK) are important frontrunners in Europe in relation to developments in DR (SEDC, 2014). In France, before sector liberalization, DR activity was triggered by the electricity utility Electricité de France (EDF) for industrial electricity customers. These units received dynamic tariffs that incentivized consumption shifting. Table 2.1 provides an overview of the most common traditional markets for electricity trading in the short and long term, based on the French trading time periods.

Time-frame	Technical system flex need	Trading mechanism	Capacity /energy trade?	Notification before real time[1]	Suited DER type	Location of DER in grid[2]	Examples of DER trading
←←← Short Term	Ancillary Services	Primary Reserves (FCR)	Capacity	<30 seconds (automatic)	EVs, residential loads, continuous loads, battery storage	TS and DS	UK: DR with dynamically controlled refrigerators (Dynamic Demand, 2005)
		Secondary Reserves (FRR)	Capacity	<15 minutes (automatic)	EVs, residential continuous loads, electrical heating, EES	TS and DS	US: EVs and stationary batteries for frequency regulation in PJM (Kempton et al., 2009; PJM, 2015a)
	System balancing	Balancing mechanism (tertiary reserves, RR)	Energy and/or capacity	13 minutes–2 hours	EVs, EES, CHP units	TS and DS	Germany: industrial loads participate in balancing mechanism (Koliou et al., 2014)
							US: aggregators are suppliers of flexibility in balancing markets (Chris, 2013)
Medium Term	Network constraints/Network capacity planning	Transmission congestion management	Energy	13 minutes–2 hours with balancing mechanism or separate	Large EV coalitions, EES, CHP units	TS	France: congestion management is traded in balancing market (CRE, 2015)
						DS	Voltalis load management of residential heating devices (Eid, 2015)
		Distribution congestion management	Energy or capacity	No dedicated market found	EVs, residential loads, electrical heating, EES	DS	Sweden: distribution time-of-use pricing for residential users. (Bartusch et al., 2011)
←←← Long Term	Spot market energy trading	Intraday market	Energy	1–24 hours	Aggregated loads	TS and DS	Elbas intraday market (Nordic region) opened to DR (Andersen et al., 2006)
		Day-ahead market	Energy	24–48 hours	Aggregated loads	TS and DS	France: the NEBEF mechanism allows trading of DR in spot market (RTE, 2013a)
							The Netherlands: pilot projects in in Breda and Hoogkerk (DNV GL, 2015; Kohlmann et al., 2011)
							US: some wholesale markets allow DR trading, such as in PJM (Mcanany, 2014)
	Generation capacity planning	Capacity market	Capacity	Year ahead	Aggregated loads	TS and DS	US: DR is participating in capacity markets in PJM, ISO-NE, NY-ISO[3] (FERC, 2015a; PJM, 2015b)
							France: DR trading in capacity markets is foreseen in 2017 (RTE, 2013b)
		Capacity payments	Capacity	Year ahead	Aggregated loads	TS and DS	No evidence found

Table 2.1: Existing markets for flexibility trading

[1] Note that these time values relate to the French system and can be different elsewhere.

[2] DS stands for distribution system and TS for transmission system. This paper focuses mainly on flexibility provision from DERs connected at the distribution level. However, if no example of DER flexibility provision at the distribution level was found for specific markets, the table presents examples of large industrial units for this purpose.

[3] ISO-NE stands for Independent System Operator New England and NY-ISO stands for New York Independent System Operator

2.4 Flexibility Needs in the System

Flexibility management can serve different purposes in electricity systems to meet the short- to long-term needs of flexibility. The following sub-sections present examples where flexibility is valuable in electricity systems.

2.4.1 Short-term needs of the system

Ancillary service markets are in place to manage transactions for upward or downward adjustments in the short to very short term. These markets are organized very close to real time and require automated load adjustment. In France, ancillary service markets are organized shorter than 30 seconds before real time for frequency containment reserves (FCRs – also called primary reserve), below 15 minutes for Frequency Restoration Reserves (FRRs – also called secondary reserve) and Replacement Reserves (RRs – tertiary reserve) for system balancing from between 13 minutes and 2 hours before real time. In the US and the UK, numerous projects present examples of DER flexibility trading within ancillary service markets (dynamicDemand, 2005; Kempton et al., 2009). As individual DERs do not provide sufficient reliable electric flexibility to be tradable in markets, aggregation is required in order to trade in organized markets.

In the US, the REG-D (Dynamic Regulation) signal is used for activating fast-responding resources like flywheels and stationary batteries (PJM, 2015c, 2013a). Within the Delaware EV project, this signal is used for activation flexibility from aggregated EVs. In this project, an EV aggregator acts as an intermediary firm between PJM (the regional transmission operator) and the flexibility service providing EVs. This aggregator sells a certain amount of capacity to the grid operator and offers this in the hourly auction for frequency regulation and for the available power capacity ($/MWh) (Kempton, 2014; Kempton et al., 2009). When participating in the frequency regulation market, EVs receive the REG-D dispatch signal from PJM and are remunerated accordingly. If the regulation service offered by the Delaware EV aggregator has not met with the performance thresholds over a specified time period in terms of correlation (delay) and precision, PJM is allowed to penalize and disqualify the aggregator (Chris, 2013).

Markets for balancing services are arranged longer before real time than ancillary services and do allow aggregated flexibility resources to participate in places in the US and Europe. In the US, for example, through the Boston-based aggregator EnerNOC, flexibility suppliers can trade their flexibility in balancing markets (Chris, 2013). In Germany, many industrial loads directly participate in the balancing mechanism; however, for aggregated loads there are still many barriers to participation in the balancing markets (Koliou et al., 2014). In the French system, such barriers have been lowered by the reduction of the minimum bidding capacities for balancing services from 50 to 10 MW in order to motivate the entrance of smaller entities like aggregators to participate in balancing mechanisms (SEDC, 2014).

A French example of small load aggregation is the aggregator Voltalis.[4] Customers contracted with Voltalis have a free Bluepod box installed in their home to reduce the operation of their electric heating devices at short time intervals when Voltalis receives a signal from the transmission system operator (TSO). The dispatch signal is mostly related to endangered electricity supply in Brittany (a poorly interconnected French region) due to network congestions.

In Sweden, the DSO can incentivize load shifts by the provision of time-of-use (TOU) prices to defer network investments or decrease congestion by incentivizing the customer to shift the load away from peak times (Bartusch et al., 2011; Bartusch and Alvehag, 2014). Unlike in the previous examples, the DSO does not trade this flexibility within a market for congestion management or deferred network investments; this is a direct incentive arrangement between the DSO and electricity users.

2.4.2 Medium- and long-term needs of the system

In the US, demand resources can also participate in wholesale and capacity markets. A Curtailment Service Provider (CSP) is the entity responsible for DR activity for electricity consumers in the PJM wholesale markets (PJM, 2013b). Demand response (DR) has been growing relatively quickly due to Order 745, which settled prices for DR equal to those for generation in the wholesale electricity markets, and it is a major supplier of capacity in most US capacity markets such as PJM, ISO-NE and NY-ISO (FERC, 2015b; PJM, 2015d, 2014).

As the first in Europe, the French system provides the possibility for DR trading within spot markets. This has been possible since 2014 with DR able to be traded in the day-ahead market through the NEBEF (Notification d'Echange de Blocs d'Effacement) mechanism.[5] In 2017 it is expected that DR will also be tradable in capacity markets in France (RTE, 2013b). Furthermore, the French TSO organizes an annual tender dedicated specifically to DR providers.

2.5 Flexibility-providing Units

There are a variety of flexibility-providing units that are able to provide flexibility services in the electricity sector. In theory, any electricity storage, consumption or production unit can be flexible, as long as its operations are (manually, pre-defined or automatically) adjusted, depending on specific system requests for flexibility. Sub-section 2.5.1 first presents the characteristics of flexibility-providing units and the next sub-sections provide insight in electricity consuming, storing and producing units.

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[4] Information on Voltalis via: www.voltalis.fr

[5] See website RTE: https://clients.rte-france.com/lang/fr/clients_distributeurs/services_clients/effacements.jsp

2.5.1 Characteristics of flexibility resources

Distributed energy resources (DERs) have specific characteristics for providing flexibility to the electricity system at large. These are closely related to the characteristics named in Table 2.3. However, they are further specified here in measurable terms. These characteristics are presented here as the *direction*, *temporal maximum power ratio, availability, activation time and location*. An overview of common DER appliances and their specific characteristics is presented in Table 2.2.

Some DERs may provide flexibility in a single direction (for instance, lighting loads and continuous loads like electric heating or cooling), while others have bi-directional capabilities and can act both as consuming and producing units (e.g. EVs, storage units, dispatchable water heaters and dispatchable household appliances). This characteristic refers to the ability of the resource to provide upward, downward or bi-directional flexibility to the system. For future anticipated load or decreased production, the system would require upward flexibility. For future anticipated production or decreased load, downward flexibility is required in the system.

Furthermore, the electrical composition is of importance in stating which system flexibility needs DERs could serve, which calls for a differentiation between *power* and *energy* resources. The power resources have a rather low energy and power ratio. Power resources can provide the electricity system with a high power value but are not able to maintain this power level for a long period of time. The energy resources have a high energy to power ratio and are more appropriate for maintaining a change in power level for a longer period of time. The power resources are therefore better suited to short-term markets (e.g. the ancillary service markets) while energy resources are better suited to long-term markets, for example, trading flexibility in the bulk electricity market.

In order to compare the different DERs with respect to this energy and power ratio criterion, the *temporal max power ratio* t_r expressed in time, can be seen as the maximum duration a DER can sustain its maximum power variation with respect to its nominal power. For some DER types, this parameter can be computed by dividing the energy range by the maximum power capacity (e.g. a stationary battery with a charging and discharging power equal to 10 kW and an energy capacity equal to 50 kWh, then the t_r becomes 5 hours). For other DERs, it may be related to physical characteristics (for instance for a water heater with thermic inertia, t_r = 30 min). The lower the *temporal max power ratio* value, the more the DER can be considered as a *capacity type* DER. This variable is intended to provide insight into differences between DER categories, although there is no singular value for all DERs in one specific category as this value is technology specific. As DERs will be gathered into aggregations to provide grid services, t_r is therefore more insightful in characterizing DER abilities to provide power capacity- or energy-related grid services.

Following the *temporal max power ratio*, the *availability* (a_r) provides an insight into the amount of time that the DER is available to provide flexibility services to the system. Unlike the previous ratio, which is based on the technical characteristics of DER, this ratio is based on user behaviour. For example, some resources, such as EVs, may only be available during specific periods of time – for instance, EVs are most likely to be available from 6 p.m. to 6 a.m. In order to compare DERs on this factor, the ratio a_r is defined as the average number of hours per week during which the unit is available, divided by the total number of hours in a week. Of course, this factor might be different depending on specific situations and each individual end user. However, to reduce complexity, this is sufficient to provide initial insights into the DER characteristics.

Furthermore, the *activation time* refers to the likelihood that some resources may be able to adjust their power much more quickly than other resources. Generally, and with the exception of CHP units which have longer ramping times of around 15 minutes, almost all electric appliances have a fast activation time, ranging from around one second to one minute (Houwing et al., 2010). Lastly, the *location* of DERs is of importance for the supplied nature of the required flexibility. For example, location-specific flexibility could be of interest for local congestion management or DG optimization. Table 2.2 presents an overview of common DERs and their characteristics.

	DER	Flexibility direction	Flexibility characteristic (power vs energy)	Availability ratio	Predict-ability	Response time	Grid DS: distribution. TS: transmission	Reference
Electrical Consumption	Lighting loads (W)	Unidirectional (upward)	New LED systems: **energy** types older lightings: **power** types	$0.2 < a_r < 0.5$ during peak hours	Good	Second	DS	(Lee et al., 2011; Lu et al., 2008; Samarakoon et al., 2012)
	Dispatchable, household appliances (washing machines, dishwasher, kW)	Bi-directional	**Power** type $5s < t_r < 5min$	$a_r < 0.1$ low *max power ratios* t_r due to max off time	High	Second	DS	(Lu et al., 2008; Samarakoon et al., 2012)
	Electrical heating/ cooling (continuous loads, kW)	Unidirectional (upward)	**Power** type $t_r \approx 15min$	$0.4 < a_r < 1$	High	Second	DS	(Samarakoon et al., 2012; Tomiyama et al., 1998)
Bi-directional	Electrochemical energy storage (EES)(kW-MW)	Bi-directional	**Power** & **energy** types $4s < t_r < 10h$	$a_r \approx 1$	Perfect	Second to minute	DS or TS	(Divya and Østergaard, 2009; Yang et al., 2011)
	Electric Vehicle (EV) (kW)	Unidirectional or Bi-directional	**Power** & **energy** types 30 min < t_r < 6 h	$0.5 < a_r < 0.9$	High	Second	DS	(Kempton et al., 2009; Pearre et al., 2011)
Generation	PV Unit kW	Unidirectional (downward)	Curtailable; **energy** type	$0.25 < a_r < 0.4$	Good a few hours ahead	Minute	DS	(International Energy Agency, 2013)
	Micro-CHP unit (kW)	Unidirectional (production mode)	**Energy** type	$a_r \approx 1$	Perfect	Rather slow (5%/min)	DS	(Houwing et al., 2010)

Table 2.2: An overview of common DERs and their characteristics (Eid et al., 2016b)

2.5.2 Residential loads and other consumption units at the residential level

Residential appliances, such as water heaters, washing machines, electrical heaters and air conditioners have comparatively low *temporal max power ratios* t_r, meaning that they do not sustain their maximum capacity for longer time periods. The time periods can range from a few seconds (e.g. for cookers) to about 15 minutes for electric space heaters (Samarakoon et al., 2012), thus providing a *temporal max power ratio* of 5s < t_r < 15 minutes. The availability depends to a large degree on the appliance being considered; electric space heaters have good availability ($0.4 < a_r < 1$), while washing machines have very limited availability due to the short-term use of the appliance ($a_r < 0.1$). For some DERs, the availabilities, for example for electric heaters and air conditioners are highly seasonally dependent. A similar rationale applies to their predictability (Tomiyama et al., 1998; Wong and Pelland, 2013). Heat pumps coupled with thermal energy storage stand out in this category; their *temporal max power ratio* can reach up to three hours without sacrificing end-user comfort levels (Arteconi et al., 2013), making them suitable for longer-term grid services such as peak shaving.

In the future, LED systems may be able to support system power variations of up to 35%, compared to humans who can observe a variation of 15% in light intensity. Therefore this technology could potentially be used to provide flexibility services within the system, particularly for public lighting (Lee et al., 2011). Older lighting systems do not have this ability; changing their power consumption would seriously impact observed light intensity (Lee et al., 2011; Samarakoon et al., 2012). LED lighting systems can maintain this power variation for significant periods of time and therefore can be considered *energy type* flexibility resources. However, their potential power modulation is relatively low in absolute values. Although their predictability is relatively good, their availability is highly dependent on the usage. Typically, public lighting would be turned on from a few hours a day during peak hours to 12 hours a day, thus we find $0.2 < a_r < 0.5$. This criterion is, however, highly seasonally dependent.

2.5.3 Bi-directional DERs: electrochemical storage and EVs

Storage units can potentially increase the level of electricity self-consumption of households and reduce power supply and transportation capacity needs (Eyer and Corey, 2010). Electrochemical energy storage (EES) units have very high availability and predictability ($a_r \approx 1$). However, whether they should be considered as *energy type* or *power type* resources depends on specific power and energy density characteristics, which is, in turn, highly dependent on battery technology, e.g. Li-ion, Ni-MH and Ni-Cd (Yang et al., 2011). Thus, it is possible to find EES units for all kinds of applications, from very fast high-power responding units (such as super capacitors, $t_r \approx 4s$) to energy type chemical batteries (such as Li-ion batteries, $t_r \approx 10h$) (Yang et al., 2011).

Most EVs[6] today have a battery capacity of around 20 kWh.[7] Their *temporal max power ratio* depends on the power of the charging station they are plugged into. Typical charging station powers range from 3 kW to 50 kW, leading to approximately a t_r of 30 min < t_r < 6 h. Because EVs are primarily used for transportation, their flexibility services are more suited to power capacity services that do not deplete the battery. Privately owned EVs, are mainly available for flexibility provision at night and weekends ($a_r \approx 0.5$), but availability could rise up to $a_r > 0.9$ through charging points installed at working places. Company fleets have slightly different usage patterns and could also be available in the afternoons ($a_r \approx 0.8$). The patterns

[6] The EV market share is today rather low everywhere (except in Norway): this is mainly due to their limited driving range, their high prices and the lack of charging infrastructure. However, these three barriers could be overcome in the near future through the joint action of technology improvements and public policies.
[7] Nissan Leaf: 24 kWh; Renault Zoe: 22 kWh; BMW i3: 19 kWh. In the future, battery characteristics are expected to increase significantly, which could change the value of EVs as DERs.

of EV usage are easily predictable especially when observing a company fleet of EVs (Pearre et al., 2011).

2.5.4 Producing DERs: micro-CHP and PV units

Micro-CHP units are small heat and electricity generating units. They have large availability and predictability since they are dedicated to heat and electricity production ($a_r \approx 1$). It is more difficult to define a *max power temporal ratio* for micro-CHP units because these units can produce electricity continuously at maximum power, as long as they are being supplied by the primary energy source (mainly gas). The availability of CHP for maintaining a change in electricity production will be based on economics logic. The control strategies of micro-CHP units are likely to take account of the costs of energy when balancing the economics (Houwing et al., 2010). Therefore, micro-CHP units would fit in the *energy type* category.

Photovoltaic (PV) units are different to other production units as their production output cannot be controlled. However, with the introduction of smart inverters, PV production can be curtailed and, considering aggregation across multiple sites, PV could even provide downward and upward reserves. However, for PV to provide upward flexibility, this would imply that PVs would need to operate below their maximum output on a continuous basis, resulting in overall economic loss. Generally, PV units produce electricity for between 6 and 10 hours a day depending on their location. Production forecasts for single units can be achieved a few hours ahead (International Energy Agency, 2013). However, predictability improves for aggregations of many solar units rather than individual units (similar to EV fleets as discussed above).

2.6 Actor Perspectives on Flexibility Management in Smart Grids

As described earlier, flexibility management can serve different purposes in the system. The objectives of flexibility management are therefore related to actor perspectives on the system. The following sub-sections present the actors within the European regulatory context in which the retail competition model prevails.

2.6.1 The distribution system operators (DSOs)

Generally, the DSO's main task is to keep electricity reliability levels above regulated thresholds by installing enough network capacity and ensuring grid maintenance. The DSO is also responsible for providing fair third-party access to consumers and producers on the electricity network. The DSO can recover its incurred costs through the established regulatory scheme. In Europe, most DSOs are subject to incentive regulation, which means that their expenses should reduce each year by an efficiency factor.

Specific investments in smart grid control devices and metering improve the insights of DSOs into developments in electricity demand and can therefore decrease operational and investment expenses. With smart metering, a DSO can benefit from a reduction in metering costs. Furthermore, the procurement of flexibility can delay the need for investments in the network. However, the procurement of flexibility through smart grid solutions can increase the operational expenses (OPEX) over time. This can counteract the tendency of the DSO to embark on this route. In several European countries there is an ongoing debate about whether smart grid investments should be left outside the regulatory benchmark.

Different levels of unbundling are possible for the DSO. When the DSO is administratively or legally unbundled (i.e. separated from production and supply while remaining under the same holding company), the holding company can maintain (financial) links between the network and the generation company. In this case, the smart grid investments by the network company might implicitly benefit other companies in the same holding. However, with ownership unbundling, the DSO and the generation company are different firms which are strictly separated with respect to the ownership of assets. In this case, the allocation of smart grid benefits would provide clear benefits that could be allocated transparently to the actors providing the added value.

The Council of European Energy Regulators (CEER) published a report in 2014 that discussed the future role of the DSOs in the European smart grid (CEER, 2014). In this report, CEER emphasized that the DSOs should provide a level playing field for other actors in the electricity supply chain. A response from the association of European Distribution System Operators (EDSO) emphasized that all actions that influence grid operations should be carefully assessed (for example, installation of new EV charging stations and DG units). Furthermore, it emphasized that if the required regulation for a new activity is of such size that it becomes closely monitored by the regulator, then this should probably be done directly by the DSO itself as an already regulated entity (CEER, 2014; EDSO, 2015).

2.6.2 The retailers

In the retail competition model, the retailers compete for their share of electricity consumers in the market. For retailers, smart metering with insights into real-time consumption could provide greater insights into consumption load curves and price elasticity, and consequently could improve the retailer's strategic position for the trading of electricity. Smart metering and real-time data measurement and communication from end-user consumption and production could make tailored contracts for direct control of devices and real-time pricing (RTP) possible, and could also support the provision of incentives for specific flexibility services (Eid et al., 2015; Hakvoort and Koliou, 2014).

Therefore, as well as supplying traditional electricity retail services, the smart grid could open up new business opportunities for retailers, for example, with real-time trading of electric flexibility services on balancing markets, ancillary services or on congestion markets (Eid et al., 2015). This role could also be fulfilled by the aggregator, as presented in the next section, which specifically focuses on enabling, management and trading of aggregated flexibility.

2.6.3 New entities: aggregators and energy service companies (ESCOs)

Due to the integration of real-time data management and control, business models could arise for new actors in the electricity supply value chain. First of all, the electricity supply service could be offered by traditional retailers. However, this service could also be provided by other actors such as aggregators or ESCOs. In the UK, ESCOs combine offers for a range of supplied services like electricity, heating, cooling and gas supply for a specific urban district (Hannon and Bolton, 2015). However, this thesis does not examine this further because of the multi-carrier nature of this actor's service provision.

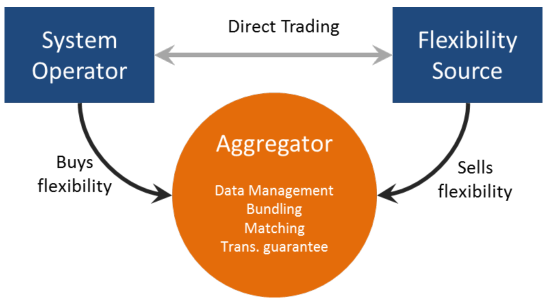

Figure 2.5: The aggregator in the flexibility trading process

The aggregator is different from the traditional retailer as it specifically focuses on the trading of flexibility services in markets. Due to its functions, the aggregator firm can be compared with intermediary firms that exist in many other sectors, for example, gas shippers in the energy industry (Weijermars, 2010). Generally, intermediary firms act as third parties between buyers and suppliers. Flexibility aggregators may not be necessary for all types of flexibility providers in the electricity sector – for example, large industrial consumers are able to provide their flexibility services directly to the TSO (see Table 2.5).

2.6.4 Customers

In the traditional electricity sector, residential electricity customers can decide which retailer to buy their electricity from. With the exception of this retailer choice in Europe, traditional electricity sectors provide few other decision variables for end users. Within a smart grid, customers could, however, be more engaged in electricity consumption through real-time insight into their own real-time consumption, increased price transparency, possibilities for local production, self-consumption and storage of electricity. The ways in which consumers are engaged can be a direct result of the arrangements that have been set out by the actors in the sector and the services that have been made available to the customer (Hakvoort and Koliou, 2014). For example, with the possibility of combining time-based pricing with the installation of in-home displays and energy management systems, consumers can have greater control over their consumption and might actively participate in reducing their electricity costs and their impact on emissions.

Even at the design phase of smart grid projects, improved engagement of end users is possible. Involvement is even recommended at an early stage; previous experience in the Netherlands has shown that privacy should be addressed carefully, even at the design stage of the smart grid project, to positively affect consumer enrolment in smart grid projects (Cuijpers and Koops, 2012; McDaniel and Smith, 2009). However, end-user engagement is not a requirement for smart grids to exist. Flexibility management could also be accomplished without active involvement of the end users through automation and direct control.

2.7 Institutions in the Electricity Sector

The potential stakeholder perspectives on smart grids presented in the previous sections are highly dependent on the institutions that are in place in the sector. Institutions in this context do not refer to physical buildings or organizations, but rather to a set of rules or regulations that affect the behaviour of actors. According to North (1984): *"Institutions consist of a set of constraints on behavior in the form of rules and regulations and, finally, in a set of moral, ethical and behavioral norms which define the contours and constrain the way in which the rules and regulations are specified and enforcement is carried out*" (North, 1984, p. 97).

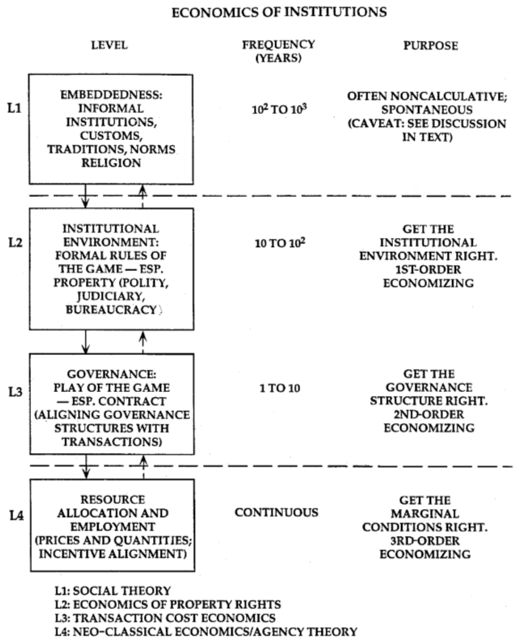

Figure 2.6: Williamson's "Economics of Institutions" (Williamson, 1998)

In behavioural economics, Oliver Williamson presents a framework that connects such (institutional) social aspects with economic theory in his "Economics of Institutions" (Williamson 1998). Williamson's framework presents how economic transactions are influenced by different institutional layers (see Figure 2.6).

The Williamson framework of institutional economics consists of four layers, representing different institutional levels that relate different economic theories to one another. Williamson's institutional model provides an insight into how social theory, economics of property rights, transaction cost economics, and neo-classical economics and agent theory can be connected to each other. However, this framework lacks insight into the interactions *between* technology and institutions. When the provision of a good or service is significantly affected by its technical constraints and requirements (for example, by the operational requirements for reliability in the electricity systems), the economic theory of Williamson lacks insight into the aspect of crucial (market) functionalities to support the overall reliability of supply.

Künneke therefore proposes including technical aspects of infrastructures that relate to the four different levels of Williamson's model (Künneke, 2008). The right side of the model is identical to Williamson's model . The left side of the model includes those technical aspects which apply to technicalities in infrastructure sectors like electricity, railways and gas (See Figure 2.7).

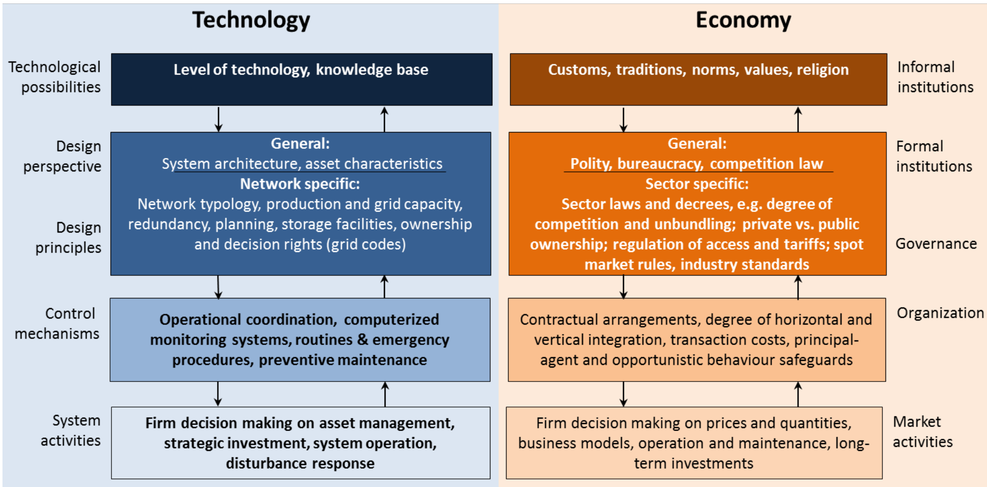

Figure 2.7: Technical and institutional design in energy infrastructures (Correljé et al., 2014; Scholten and Künneke, 2016; Williamson, 1998)

Starting with the institutional economic (right) side of the model, the first and most general layer represents the cultural norms, traditions and religion, and relates to social theory. It deals with informal institutions and cultural aspects that are often not explicitly formulated or codified but, rather, are shared convictions by members of a community (Scholten and Künneke, 2016).

Layer 2 represents formal institutions i.e. the "rules of the game', such as the official state bodies, laws and regulations. The formal institutions also describe the design of competition, ownership and regulation. These can be marked as the general formal institutions. More sector specific are the sector law and decrees – for example, the existing possibilities for liberalization and unbundling, possibilities for substitution and the type and cost-structure of the good or service. The private vs. public ownership and decision rights are sector specific. "Different systems of property rights (private, public, collective, and common) influence the behaviour of actors differently and produce different outcomes" in light of efficient allocation of their scarce resources (Correljé et al., 2014). Other sector-specific regulation can be focused on reducing externalities – for example, rules on maximum CO_2 emissions, rules on data privacy in the sector and the rules for universal access.

Level 3 concerns the "play of the game', given the rules in level 2. Attention goes to the contractual arrangements among actors, i.e. the modes of organization that accommodate market transactions. This could be done through, for example, spot markets, long-term contracts, vertically integrated firms, or regulated state-owned enterprises. In this thesis, the level of analysis starts at this level, assuming that the formal institutions are as set by European policy with competition law and unbundling of the DSO.

Finally, Level 4 relates to short-term market activities, company internal decision-making on prices, quantities and investments, business models and optimization of (O&M). The sum of actor activity results in a certain market outcome, usually expressed in terms of static and dynamic efficiency and/or the effectiveness with which a specific good or service is provided to consumers. In the energy sector, this is usually translated into how the availability, affordability and acceptability (and increasingly sustainability) of electricity, gas, oil or heat can be most efficiently achieved. Many public service provisions may also be attached to this list – for example, universal service obligations or safety standards. It is important to note that the institutional environment (layers 1 and 2a) frames the setting for the governance and organizational arrangements (layers 2b and 3) that in turn incentivize actor behaviour on this fourth layer.

On the other side of the framework are the technical aspects of the infrastructure. In the first level (left side of Figure 2.7), the technical possibilities of the given technology set the systemic environment, the level of technology and knowledge base. In Level 2, the design perspective and design principles represent the technical constraints and abilities due to system architecture and network-specific characteristics and requirements. In Level 3, the technical control mechanisms represent all the (automated) coordination mechanisms that are in place in order to sustain system reliability and abide by network and production constraints. Lastly, in Level 4, the actual system activities take place, for example, with firms deciding on the management of their assets in real time (Correljé et al., 2014; Scholten and Künneke, 2016).

3 Design Framework for Flexibility Management

Examples of institutions in the European electricity sector are the rules on retail competition and unbundling for the DSO. The basics of this model are enforced by the European Commission with the laws on functional and legal unbundling of network operators (CEER, 2013a; Newbery, 2002). In this thesis, institutions are all the rules and arrangements that guide end-user behaviour, with a specific focus on the activation of electric flexibility.

This chapter presents a techno-institutional framework for the design of flexibility management in electricity systems.

3.1 A Techno-institutional Perspective on Electricity Systems

From a technical point of view, the electricity value chain is organized by the key functionalities of *electricity production*, *transmission*, *system operation*, *distribution* and *retail*. In vertically integrated electricity utilities, all these functions are managed centrally by a single (public) entity. However, sector liberalization has resulted in the unbundling of the naturally monopolistic functions (like network operation and system operation) from the functions in which competition could be introduced. With this transition, the need has arisen for effective organizational structures to support such transition, in which both the market activities and the technical reliability activities can be fostered.

The organization of responsibilities for critical functionalities within energy systems has been described by Correljé, Finger, Groenewegen, Künneke and Knops (Correljé et al., 2014; Finger et al., 2005; Knops, 2008; Künneke, 2008). They have built on the work of Oliver Williamson who showed how institutions influence economic interactions (Williamson, 1998). Künneke discusses the importance of interrelationships between technological and institutional design in the liberalization process. The framework of technical and institutional design in energy infrastructures is focused on generic aspects for securing the roles for critical functions, i.e. the functions that are required to secure reliability of supply. It presents the interconnection between infrastructure (technical) and the institutions (markets) to fulfil fundamental reliability functions in electricity systems. He and his co-authors show that until now, liberalization has focused mainly on the institutional adaptations in the sector, leaving the technical operations equally organized, as in the monopolistic situation with central planning and control. Smart grids, as a technical innovation in the sector, could call for new institutional design. However, as most European systems do not have any reliability issues at the moment, flexibility management in this thesis mainly serves secondary purposes such as cost reduction for actors involved. A more operational framework is proposed that directly structures how new regulation, incentives and markets can *enable* flexibility management.

3.2 Technical-institutional Design for Flexibility Management

In the organizational dimension, Scholten's definition of organizational or management structures identifies two core aspects of organization: *"It entails a division of tasks or responsibilities among the configuration of entities involved in an activity (who does what, when, and how); and it relates to the nature of entity interaction or coordination employed in an activity (hierarchical, horizontal, or in between)"* (Scholten, 2013: 181). These two aspects provide an insight into the way in which interactions are organized and affect the necessary tools to make those interactions successful. This thesis takes account of Scholten's division to better classify different smart grid cases based on the interactions taking place to enable flexibility management. This division is taken into account in the smart grid case studies covered by the thesis.

The technical-institutional design framework for flexibility management in this chapter introduces these incentives within the economic layer of the framework. The framework comprises three layers: a techno-institutional layer, an economic layer and an operational layer. Flexibility management is defined as the application of the four flexibility management variables: 1) the division of responsibilities (**who**); 2) for management of the flexibility from appliances (**what**); 3) by specific means (**how**); and 4) for specific time-dependent system purposes (**why).** There are also two organizational variables: *the **number of actors** involved* and *the **nature of transactions.*** See Figure 3.1 and Table 3.1 for a presentation of the techno-institutional design framework.

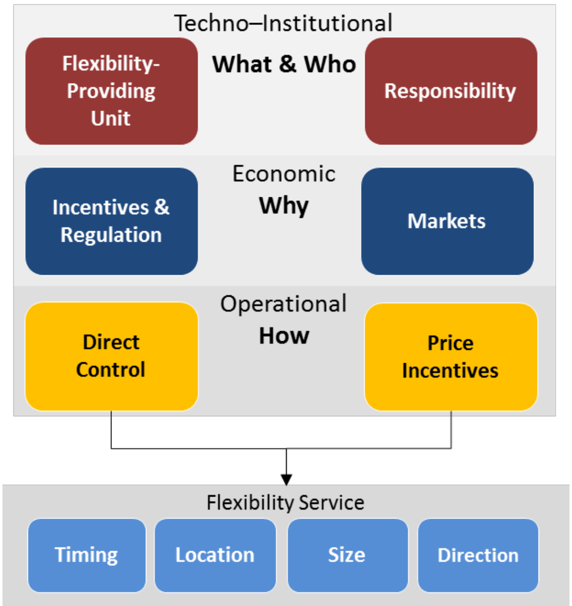

Figure 3.1: Techno-institutional framework for flexibility management in electricity systems

Flexibility management design variables	**Options**	**Base case:**[8] **Flexibility management in Europe**
Who is responsible?	DSO, retailer, aggregator and/or other actor	At high voltage level: TSO At low voltage level: no specific responsibility for flex management
What flexibility-providing units are managed?	e.g. CHP, PV, EV and/or household appliances	At high voltage level: large generators and customers At low voltage: none
How is flexibility activated?	Price incentives or direct control	At high voltage level: through direct control & price incentives At low voltage: normally no flexibility activated, sometimes if retailer/DSO provides a (price) incentive (Eid et al., 2016d)
Why is this flexibility activated?	**Regulation** (direct regulation which settles control on devices), **incentives** or **markets** (balancing, day-ahead, ancillary services and/or other local markets for flexibility)	Existing TSO markets: e.g. ancillary services, balancing market, congestions markets, etc. At low voltage: no specific market available
Number of actors involved	1 or more	Single buyer (TSO), many sellers of flexibility At low voltage: not specified due to absence of market
Nature of **transactions**	Hierarchical, hybrid or horizontal	Horizontal At low voltage: Not specified due to absence of market

Table 3.1: Flexibility management framework (Eid et al., 2016a)

3.2.1 Responsibilities (who)

The first aspects of importance for flexibility management are **responsibilities**. The actors at the distribution grid that could be responsible for flexibility management include the DSO, retailer, aggregator and/or other actors like the ESCO (see Section 2.6.3) or TSO. Depending on the actor's responsibility and the current business model, the flexibility is used for the specific market activities in which this actor is involved and/or the services that the actor provides. Different actors might have specific interests in the use of flexibility; the retailer might use flexibility for portfolio optimization, while the DSO might use it to reduce congestions, for example, as happens in Sweden (Bartusch and Alvehag, 2014). However, the TSO is the chief entity responsible for ensuring a balance between electricity supply and demand in the system and might use flexibility for solving transmission network congestions.

[8] A more comprehensive overview of the use of flexibility in traditional markets can be found in (Eid et al., 2016b).

For the DSO, the level of engagement in activities for flexibility management, however, remains dependent on the regulated remuneration for the activation of such flexibility. In Europe, most DSOs are subject to incentive regulation, which means that their expenses should reduce by an efficiency factor each year. If the procurement of flexibility through smart grid solutions increases OPEX, this would counteract the tendency of the DSO to embark on this route (Eid et al., 2016c).

3.2.2 Flexibility-providing units (what)

An actor can assume responsibility for managing the flexibility of a specific (set of) household appliances or DERs. These two types of flexibility units are combined under the term flexibility-providing units. This could include specific large appliances such as CHP units, heating units or EV charging units. Or flexibility could be provided by the entire household consumption, for example, through the provision of a time-based tariff. Each appliance has specific technical abilities for providing specific flexibility services (Eid et al., 2016b). For a wider overview of such appliances see Section 2.5.

3.2.3 Incentives, regulation and markets (why)

Actors should be motivated to utilize flexibility from DERs, for example, through incentives, regulation and/or the settlement of flexibility markets. Incentives for flexibility could entail financial subsidies to compensate for the costs involved in the activation of flexibility from end users.

Regulation, however, could require a specific set of appliances to provide flexibility to the system in order to reduce public expenses for the local grid. For example, a national law could regulate that all installed CHP units should supply flexibility to the balancing markets for a fixed number of hours per year.

Another way to motivate actors is through the settlement of markets for flexibility services. Markets for flexibility that already exist are those managed by the TSO and partly by the market operator. This method is similar to the markets that already exist at the national level, but similar arrangements could be set up at the distribution level. However, the (traditional) central single-node perspective does not take account of the location-dependent need for flexibility in case of (distribution) network congestions. Markets for flexibility management at the distribution level could therefore include locational aspects by defining price areas/nodes with zonal or nodal markets.

3.2.4 Signals (how)

There are different ways to activate electric flexibility. Signals are mainly direct control, semi-direct control and indirect signals (also called price signals) (Eid et al., 2016d). **Direct control** means that a central actor (like an aggregator) has direct access to control the operation of contracted devices. Automation and direct control provides secure flexibility within a specific time and location for the procuring actor and makes the process easy for the end user because the end user does not have to manually activate its units. **Semi-direct control**, however, refers to the ability of end users to pre-define time bands for which the devices provide flexibility, and after which the operations of the devices are automatically adjusted**.** Semi-direct control is often used along with a price signal (explained hereafter) to automate the activation of devices at low-price time periods.

Indirect signals refer to price-based signals. The flexibility obtained from these types of arrangements refers to *"changes in electric usage by end-use customers from normal consumption patterns in response to changes in the price of electricity over time"* (DOE, 2006). There are multiple time-based pricing options available, ranging from RTP, critical peak pricing (CPP), TOU and peak-time rebates (Newsham and Bowker, 2010). The price options differ mostly in relation to the price variability that they represent in time. Real-time prices change very frequently (from around every 15 minutes to every hour), while TOU prices can change on a four-hourly time basis. Unlike with direct control, indirect control gives end users the freedom to participate in the provision of flexibility services. Therefore those signals do not provide security on the expected capacity of flexibility.

3.2.5 Number of actors involved and nature of transactions

Organizational variables relate to the way in which the actors are organized among themselves. These variables are the **number of actors** involved and the **nature of their transactions** (Scholten, 2013). The nature of transactions can be horizontal, hybrid or hierarchical. When a single actor manages the flexibility, it naturally presents a hierarchical nature of transactions between end user and the central deciding actor. However, when two or more actors are involved with flexibility management, the nature of the transactions can be horizontal or hybrid. With horizontal organization, all of the actors have equal influence on the management of flexibility. With hybrid transactions, it may be the case that the transactions are not arranged entirely horizontally, but that one specific actor is appointed to manage the flexibility on behalf of other actors.

3.3 Conclusions

This chapter presents the framework for flexibility management and the most important design variables for flexibility from a techno-institutional perspective. It provides a basis for the analysis of existing and new design alternatives for the management of flexibility. Flexibility management is defined as the application of the four flexibility management variables: 1) the division of responsibilities (**who**); 2) for management of the flexibility from appliances (**what**); 3) by specific means (**how**); and 4) for specific time-dependent system purposes (**why**). There are also two organizational variables: the **number of actors** involved and the **nature of transactions.**

Previous work has provided a framework for **fundamental or critical functions** in electricity systems. These fundamental functions are the backbone of processes within the system being considered. These functions are therefore called critical functions by Scholten and Künneke (Künneke, 2008; Scholten, 2013). Their framework can be applied to the arrangements of such fundamental functions within network sectors.

Unlike in previous work, the framework presented in this chapter focuses on flexibility management as an **efficiency-improving function**. It is complementary to the previous framework as it describes flexibility management within a system in which the fundamental functions, the backbone of the system, are already organized effectively. These efficiencies in the electricity sector have come about as a result of advancements in the IT sector. Flexibility management, as presented in this chapter, therefore serves the cost-reduction objectives of actors involved through the integration of IT in the electricity system. Similarly, the integration of IT could provide a range of possibilities for efficiency gains in other sectors as well. The design variables presented in this thesis (**who** is responsible, for **what** efficiency gains, **how** and **when**) provide a useful structure to follow for the organization of these new responsibilities for efficiency gains.

The next two chapters present case studies in which flexibility management is applied within the current European regulatory context (Chapter 4) and new regulatory contexts (Chapter 5). For each case study, the four flexibility management variables and the two organizational variables are described. The information from these case studies is taken from publicly available material and from interviews with the project managers involved. Insights into the different flexibility management variables can provide an indication of how well the organizational approach suits the European regulatory context and what possibilities exist for upscaling in a retail competition context.

4 Centrally Managed Flexibility

The information in this chapter is based on the papers published in *Utilities Policy* entitled "Time Based Pricing and Electricity Demand Response: Existing Barriers and next Steps" (Eid et al., 2016d), "Aggregation of Demand Side Flexibility in a Smart Grid: A Review for European Market Design" in IEEE (Eid et al., 2015) and "Demand Response in Europe's Electricity Sector: Market Barriers and Outstanding Issues" (Eid, 2015).

This chapter provides an overview of case studies of flexibility management with mainly one actor leading the management of flexibility that is resulting from the end user. The main aim is to provide an answer to the flexibility management variables (who, what, how, when). Aspects of social acceptance are therefore left out of the analysis and are assumed to have been dealt with well enough for the project to develop.

The case studies have been chosen as they: 1) represent the diverse purposes for which flexibility is used within the current European retail competition context; 2) have been rolled out nationally and; 3) are based on publicly available material. One aspect of all these case studies in Europe is that one specific stakeholder always leads the management of flexibility. Therefore the variable of responsible actor has been used to categorize the cases (see Table 4.1). Sections 4.1 to 4.4 present the different flexibility management case studies. Even though this thesis focuses on flexibility management at the distribution level, Case Study 1 is an exception and shows how large consumers provide flexibility through aggregators for balancing or ancillary services.

Flexibility management design variables	**Case Study 1**	**Case Study 2**	**Case Study 3**	**Case Study 4**
Who is responsible?	Market-focused aggregator	Network-focused aggregator	Local DSO	Retailer
What appliances are managed?	Large industries and small (hydro) generators	Household electrical heating	Household consumption	Household consumption
How is flexibility activated?	Direct control	Direct control	TOU tariff	TOU tariff
Why is this flexibility activated?	Short-term for balancing/ancillary services	Short-term transmission congestion	Network peak hours	Day-ahead supply optimization
Number of actors involved & **nature of transactions**	1: hierarchical	1: hierarchical	1: hierarchical	1: hierarchical

Table 4.1: Case studies representing flexibility management in existing regulatory context

4.1 Case Study 1: Flexibility Management by a Market-focused Aggregator

The first case study looks at aggregators who mainly serve large industries or commercial consumers. In France, Energy Pool is an aggregator (flexibility variable **who**) that started operating in 2008. Its clients are mainly large electricity consumers like data centres, hospitals, residential and tertiary buildings, refrigerated warehouses, water cleansing and treatment facilities, and EVs (flexibility variable **what**). The total flexibility managed by this aggregator consists of around 1,000 MW capacity in the form of load reduction. Energy Pool takes charge of optimal decision-making for the end user: it identifies the flexibility potential, integrates the flexibility into the normal business processes of its clients through direct control (flexibility variable **how**), and offers the flexibility in different markets. These markets are the balancing markets, the day-ahead and intraday markets, security reserve markets (long-term contracts and emergency operations) and capacity markets (mid-term or long-term contracts – flexibility variable **why**). Energy Pool clients receive specific payments for their participation in load management programmes. Energy Pool now also operates in the UK and Belgium and has contracts with the TSOs in those countries (EnergyPool, 2014).

Another similar example of an aggregator is Flextricity. Flextricity is an aggregator (flexibility variable **who**) that started operating in 2004 in the UK. Flextricity provides both generation and load aggregation, meaning that it can incentivize clients for upward and downward flexibility and eventually trades this flexibility in markets. Flextricity's clients are large industrial and commercial customers (providers of more than 500 kW of capacity) and owners of small hydro and stand-by generators (flexibility variable **what**).

There is generally no cost for the consumers involved to participate in Flexitricity`s aggregation programmes, as the company itself installs the communication, metering and control equipment (flexibility variable **how**). The flexibility is supplied to short-term operating reserve (generators), which is a service for the provision of additional active power from generation or demand reduction if power fails or demand is higher than expected. Furthermore, flexibility is used for triad management, which is carefully targeted generation and demand flexibility to optimize revenues for the businesses involved in contingency situations. Lastly, flexibility is provided for frontline generation and load adjustment at short notice (below 10 seconds for 750 kW or more) (flexibility variable **why**).

4.2 Case Study 2: Flexibility Management by a Network-focused Aggregator

Voltalis, which has been operating since 2006, is an aggregator that activates electric flexibility from residential users (flexibility variable **who**). Customers contracted with Voltalis have a free Bluepod device installed in their homes. This device controls operation of the electric heating system (flexibility variable **what**) at short time intervals when Voltalis receives a signal from the TSO, based on endangered electricity supply sufficiency (flexibility variable **why**). In this programme, customers with a Bluepod installed automatically receive a direct control signal on their heating unit (flexibility variable **how**), but can opt out by pushing a button on the device and using their heater as normal. Users do not receive a price difference for electricity or any other financial benefit, but they see a reduction in their normal electricity bill (usually 5 to 10%) as a result of the interruptions to their electricity supply. The revenues that the retailer loses due to such interruptions are paid back to the retailer through a compensation mechanism. The advantage of this type of flexibility is that it requires no additional tariff settlement and is therefore easy to implement.[9]

4.2.1 Nature of the transactions and number of actors involved

In all three of these aggregator cases (Energy Pool, Flextricity and Voltalis), the nature of the transactions between actors can be seen to be hierarchical. This is because it is mainly the aggregator who is able to adjust end-user flexibility to serve market objectives and has a position of monopoly on this flexibility for that specific user.

Apart from the aggregator, no other actor is involved in the activation of flexibility of the end user. Therefore only one actor is involved in each of these cases. With Voltalis, the flexibility of the end user is solely managed by the aggregator based on signals from the TSO. As this control only achieves upward flexibility due to decreased consumption, this flexibility activation does not create limitations for the local network capacity. However, network limits could be reached in the operations of the other two aggregators (Energy Pool and Voltalis) if the central balancing markets simultaneously required large electricity flows and the network could not support those transactions. The projects described mainly consider the interests of the aggregator, without taking account of the effect on the network. Furthermore, since the aggregators affect the programme responsibility of the retailers involved, there are penalties that need to be paid when unexpected changes in overall end-user consumption take place (Eurelectric, 2014).

4.3 Case Study 3: Flexibility Management by a DSO

Sweden is one of the few countries in Europe with a 100% smart meter roll-out (Eurelectric, 2013). A portion of the customers from the Sala Heby Energi Elnät AB DSO (flexibility variable **who**), the electricity distribution area that covers the provincial country town Sala and its environs, receive a TOU price for their electricity distribution service (flexibility variable **how**). The project started in 2006 with a small group of single-family homes under a phased implementation from 2006 to 2009. As of April 2012, the electricity retailer Sala Heby Energi AB offered all their residential customers an electricity supply contract that involved hourly prices against the spot price in the Nordic power exchange.

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[9] See www.voltalis.com

Prior to the introduction of the demand-based TOU electricity distribution tariff (henceforth referred to as the demand-based tariff), all households in the utility's local electricity distribution area were charged according to a conventional distribution tariff composed of an annual fixed access charge (SEK/yr), the rate of which was dependent on fuse size, and a variable distribution charge (SEK/kWh). Alternatively, the demand-based tariff consisted of the fixed access charge (SEK/yr) and a variable distribution charge (SEK/kW), calculated based on the average of the five highest hourly meter readings during peak hours (flexibility variable **why**), which was applied for the entire household electricity consumption (flexibility variable **what**). In off-peak hours, electricity distribution was free of charge.

During the programme, households experienced an average reduction in individual peak demand of between 9.3% and 7.5%. When considering the peak in the distribution system, there was an average reduction of between 15.6% and 8.4%. The total shift from peak to off-peak hours was between 2.4 and 0.2 hours (Bartusch and Alvehag, 2014). Individual households saw a decrease in costs of between 14% and 41% over the duration of the project. An analysis of the project attributes some of the savings to prices that were set too low (Bartusch et al., 2011).

4.3.1 Nature of the transactions and number of actors involved

Since, in this case, the DSO is the only flexibility manager and provider of the TOU tariff, the nature of the transactions here is also hierarchical (from the DSO directly to the end user). There is no flexibility signal resulting from any other actor beside the DSO and therefore the number of actors involved is one.

4.4 Case Study 4: Flexibility Management by a Retailer

In France, the retailer EDF (flexibility variable **who**), provided an option of a time-based tariff for its clients (named the Tempo Tariff), through a combination of CPP and TOU pricing (flexibility variable **how**). In 2010, EDF had around 350,000 residential customers and more than 100,000 small business customers using the Tempo Tariff (flexibility variable **what**). Under this tariff scheme, specific days are distinguished according to prices using a colour system. The scheme further indicates whether an hour is one of eight off-peak hours. These prices are related to day-ahead prices for electricity (flexibility variable **why**). Customers can adjust their consumption either manually or by selecting a program for automatic connection to and disconnection of separate water and space-heating circuits (flexibility variable **how**). It is estimated that for the average 1 kW French house, the Tempo Tariff brought about a reduction in consumption of 15% to 45%. On average, customers saved 10% on their electricity bills (Toritti et al., 2010). This is significant for overall consumption, especially given that the majority of French households rely on electric heating during harsh winters.

4.4.1 Nature of the transactions and number of actors involved

In the case of EDF, it is the retailer that presents the time-based tariff to the end user. Since the distribution tariff continues to be fixed and no flexibility management takes place from the DSO or any other actor, the nature of the transactions here is hierarchical with only one actor involved in the flexibility management activation from the end user.

4.5 Discussion

The examples presented in this chapter describe the use of flexibility by a central actor managing flexibility within the European retail competition context. In all of the case studies presented, one single actor is responsible for flexibility management and therefore the electric flexibility is applied to serve a single stated objective: portfolio optimization, system balancing or network congestion management. Consequently, the approaches presented do not take account of the simultaneous time and location-dependent needs for flexibility. Problems that result due to such a distinction in the design of flexibility management are the **technical coordination** and **economic valuation issues**. These two issues are described in further detail in subsequent sections.

4.5.1 The technical coordination issue

Actor functions within the European retail competition model are specifically focused on unbundling network and supply activities in order to support competition at the wholesale level. To enable competition over the entire electricity system, electricity markets are centrally located at the transmission level, taking a single-node perspective on the electricity system. Though these markets ensure competition at the wholesale level, they do not take account of the impacts on (distribution) network constraints. The following examples provide insights into how the coordination issue takes place.

In Germany, for example, oversupply of wind electricity can result in a need for increased consumption or reduced production (downward flexibility), while simultaneous network congestions result in a need for reduced consumption or increased production (upward flexibility). Consequently, at certain points in time for a specific location in the network, the flexibility required can be competing when considering both the location (network capacity) and timing (oversupply of wind) of flexibility. Without coordination mechanisms for the time of the provided flexibility and the location, a coordination problem will occur (Hakvoort and Koliou, 2014). In the current European context, however, the DSO is primarily focused on maintaining and installing sufficient distribution network capacity. The DSO receives a regulated income to support this primary focus. If, as a natural monopoly, the DSO was allowed/incentivized to provide time-based signals, this could result in market-disturbing effects for other actors such as retailers, as end users would need to adjust their consumption based on distribution tariffs while the retailer would have scheduled regular consumption patterns. However, in order to sustain reliability of supply and reduce the need for network investments, it could be profitable from a social perspective to do so. Therefore, adjusting this coordination issue would require re-consideration of regulation in liberalized electricity markets for the DSO and retailers, and possibly extending the role of the DSO with regard to flexibility management and responsibilities.

This technical coordination problem is not present, however, in the Voltalis case, as here flexibility is provided only in an upward direction with reduced consumption, and therefore does not result in network congestions.

The coordination issue therefore requires that the location-dependent network needs for flexibility are taken into account along with the supply and balancing needs for flexibility. This problem is located at the highest level within the techno-institutional flexibility management framework and requires re-consideration of responsibilities (flexibility variable **who**), regulation, markets and incentives for flexibility (flexibility variable **why**).

Such improved coordination could take place in several ways, for example by adding new responsibilities to existing actors (such as for the DSO), and/or introducing new regulation, incentives or markets for existing actors to ensure coordinated network and supply flexibility management, or including a new (regulated) actor who takes on this responsibility for coordinated network and supply capacity allocation. In the TSO-DSO data management report, those new roles and responsibilities have been introduced especially for the DSO and TSO (CEDEC et al., 2017) with regard to flexibility management and the related data management. The flexibility management is, as presented in this report, supported by a backbone of real-time data collection, data processing, data analysis, data storage and data publication to the rightful actor(s). As this task is highly confidential and both the TSO and DSO are regulated actors in the electricity sector in Europe, it is a logical choice to make these tasks part of their responsibilities. According to the recommendations in the TSO-DSO data management report, the roles given to stakeholders with regard to flexibility management would have to support an integrated electricity system in which there is:

1. **Effective use of flexibility:** Flexibility is used according to market rules while singling out market risk. Harmful interferences between congestion management and balancing are avoided.
2. **Non-discriminatory provision:** The provision of flexibility is non-discriminatory, allowing flexibility provision by any stakeholder.
3. **Data privacy and transparency:** Data insight is given only to rightful third parties, with end-user consent, and supports efficient market functioning while adhering to privacy regulation. The system should ensure neutrality of the data manager in the provision of flexibility. Data management should follow strict regulation with regard to privacy and the TSO-DSO data exchange is standardized.

The next chapter provides examples of case studies that present methods of flexibility management with interactions between multiple stakeholders that try to tackle points 1 and

2 above: the effective use of flexibility in a non-discriminatory manner. Point 3 is not analysed in this thesis but is a recommended step in the design of data management methods when the services for which the data is used are clear.

4.5.2 Economic valuation

The case studies presented in this chapter demonstrate the use of electric flexibility as an efficiency-improving function for the electricity sector as a whole. They demonstrate the marketing of extra-attained electric flexibility in existing central markets (Case Studies 1 and 2) or show how flexibility decreases the costs of existing actors (Case Studies 3 and 4).

However, as stated in the previous section about the coordination issue, the case studies presented would not ensure that network congestions would be avoided in the long term. If the central market (for example in Case Studies 1, 2 and 4) requires electric flexibility, this could result in the simultaneous provision thereof leading to network congestions.

Therefore, to have both the coordination issue in order and the economic valuation in place, new responsibilities, incentives and/or market models would need to be set in place. The next chapter will provide examples of the implementation of such new market models. Within the existing markets in the European retail competition context, actors are not incentivized to trade flexibility in a way that simultaneously takes account of local network and market needs. Where there are no responsibilities, regulation, markets or incentives for coordinated flexibility, there is no business value for such flexibility, and this therefore results in an economic valuation problem.

Several issues create barriers to economic and technically efficient flexibility management practices. Firstly, with regard to aggregators, in many places there are high start-up costs associated with the activities for aggregators' trade flexibility due to the high minimum bidding values that are set for trading in balancing and/or other central markets. A second issue relates to the need for compensation mechanisms between independent aggregators and retailers that guarantee that electricity suppliers are not penalized for imbalances caused by activities of (independent) aggregators (Eurelectric, 2015). Whenever the aggregator reduces or increases electricity consumption, the deviation should then be reported in a schedule to the TSO, who will correct the respective balance. Financial compensation should be paid to the balance group for the energy that is consumed or not consumed due to the control of the aggregator.

Thirdly, in Europe, most DSOs are subject to incentive regulation, which means that their OPEX should decrease by an efficiency factor each year. However, the procurement of flexibility through smart grid solutions can increase the OPEX over time. This, in turn, can counteract the tendency of the DSO to embark on this route. Fourthly, there is no regulation with regard to the responsibility for real-time metering and data management by the DSO or another regulated actor. It is suggested that this role of metering and data management should be a regulated actor in order to support neutrality and avoid disturbances in market functioning. Linked to this are the investment cost for smart meters which are relatively expensive. For example, in Europe, the installation cost of a smart meter is between €200 and €250 on average. An important question is who initiates the installation of smart meters? Should it be the DSO, consumer, the retailer or the aggregator? And furthermore, who is in charge of the management of data from the consumer? If a market party only is in charge of the end-user data, this could lead to monopolistic practices which could hamper efficient market functioning. It is therefore suggested that both the investment in smart meters and the management of data, should be carried out by a regulated actor like the DSO. If the DSO makes the investment and manages the data, the DSO is required to adhere to rules with regard to the management of data and privacy, and can grant access to the data only with the consent of the end user for specific market parties with whom the end user is contracted. This would safeguard that there would not be any market party with a competitive advantage over other market participants.

4.5.3 Regulation and scalability

Two points are of interest in discussing the suitability of cases to the European retail competition context. Firstly, to what degree are multiple retailers able to sell their electricity to end users simultaneously? And secondly, what is the degree of complexity involved with upscaling this methodology for further development in Europe?

As the approaches in this chapter are based on existing actors who extend their services in existing markets, all the case studies make it possible for multiple retailers to compete for their share of consumers. However, in general, adjusted regulation of the DSO would be needed to allow for distribution TOU tariffs because of the discriminative signals this could give to the overall electricity price and therefore the revenues of retailers. This is mainly the case if the price is not known *ex ante* and it cannot be internalized by retailers and end users. When, however, the TOU price is known, retailers, aggregators and end users can take account of those prices in their scheduling and therefore do not suffer negative consequences from the DSO interventions.

A further point of interest is the incentive regulation that motivates the DSO to reduce operational and/or capital expenses (CAPEX) in time by an efficiency factor. The question then arises of whether investments for flexibility management are being recovered if these are being kept within the current regulatory benchmark.

4.6 Conclusions

This chapter presented case studies of flexibility management applied within the existing European regulatory context. In all the case studies, one specific actor leads the use of flexibility. They demonstrate how the use of electric flexibility decreases the costs of existing actors (Case Studies 3 and 4) or demonstrate the marketing of extra-attained electric flexibility in existing central markets (Case Studies 1 and 2). The case studies presented in this chapter therefore demonstrate the use of electric flexibility specifically serving an efficiency-improving function for the electricity sector as a whole. The approaches presented do not take account of the simultaneous time- and location-dependent needs for flexibility.

Problems that potentially arise due to this approach to flexibility management are the **technical coordination** and **economic valuation** issues. The technical coordination issue relates to the fact that the electricity flows are network dependent and all flexibility flows that serve one objective (for example, portfolio optimization or balancing services) must abide within network constraints. If the demand for flexibility cannot be covered due to limited network capacity, a single directed electricity management method cannot take account of simultaneous network and supply needs.

The economic valuation problem arises from the fact that a lack of a market and incentives exists for actors to trade for flexibility services that take account of the technical coordination issue. The following chapter presents case studies of flexibility management within the new regulatory context.

5 Decentralized Managed Flexibility

The information in this chapter is based on the paper published in the journal Energy entitled "Market Integration of Local Energy Systems: Is Local Energy Management Compatible with European Regulation for Retail Competition?" (Eid et al., 2016a).

This chapter provides an overview of cases of flexibility management where more than one actor leads the use of flexibility. Case Studies 1 to 3 are located in the Netherlands, while Case Study 4 is located in Germany. The descriptions are intended to focus on the organization of flexibility management (who, what, how and when). The case studies have been chosen to represent the diverse purposes and methods for which flexibility is used. They are not meant to be exhaustive but are meant as examples within a specific category. Aspects of social acceptance are left out of the analysis.

The three Dutch projects were completed at the end of 2015. These projects were exempted from Dutch electricity regulation to enlarge their experimental space. The projects are part of the group of "innovation program intelligent networks" (IPIN).

The German project is still operational and was initiated with the help of a subsidy from the European Commission. Unlike the Dutch projects, the German project is an example of decentralized management of flexibility where the local network owner and retailer are the same entity. Table 5.1 summarizes the design variables for flexibility management for the case studies.

The category names in the table refer to the method or actor supporting the flexibility management within the case study. In Case Studies 1 and 2, a local market is used as an approach for coordinating flexibility management. In Case Studies 3 and 4, however, a centrally appointed actor is responsible for flexibility management. The case studies presented require significantly different regulation to that applied in traditional retail competition contexts. Therefore, each case description ends with a reflection on the nature of the transactions, a comparison with the retail competition model and possibilities for upscaling. The case examples show a high technical coordination of flexibility management for both supply and network functionalities.

Flexibility management design variables	Case Study 1: Multi-objective Optimization	Case Study 2: Dynamic Pricing	Case Study 3: Local Aggregator	Case Study 4: Local Integrated Utility
Who is responsible?	DSO, retailer and customer preference	DSO and retailer	Aggregator: direct DSO and BRP: indirect	Cooperative: direct (takes role of DSO and retailer)
What appliances are managed?	PV panels, EVs, heat pumps, washing machines, and micro CHP	PV panels, smart washing machines and heat pumps	PV panels, heat pump operation, electric boiler and fuel cell	Wind, solar PV, battery, and biomass plant (district heating, storage)
How is flexibility activated?	Direct control	Dynamic pricing and semi-direct control on smart devices	Direct control	Direct control
Why is this flexibility activated?	For reducing network peaks and supply optimization in time-steps of 5 minutes	For reducing network peaks and day-ahead market optimization with time-steps of 2 hours	For reducing network peaks and services in balancing markets in time-steps of 5 minutes	For reducing network peaks and provision of frequency control services in time-steps of 15 minutes
Number of actors involved	3	2	1	1
Nature of transactions	Horizontal	Horizontal	Hybrid	Hierarchical

Table 5.1: Overview of the flexibility management cases in new regulatory contexts

5.1 Case Study 1: Multi-objective Optimization

"Power Matching City" (PMC) is a project located in the Dutch city of Hoogkerk (see Figure 5.1). Three main actors are involved in the management of flexibility: the consumer, the DSO and the retailer (flexibility variable **who**). The project covers 40 households with installations of solar PV, EVs, heat pumps, micro CHP and a power matcher device (flexibility variable **what**). A central operating system in PMC is the PowerMatcher, which brings together the demand and supply of different flexibility-providing units through software agents. Each of these agents bids individually in the local electricity market for the price at which they want to buy or sell electricity. In addition to these software agents for flexibility-providing units, three other stakeholder agents are represented:

- The DSO agent, which represents the interest of the network operator.
- The trade dispatch objective agent, which represents the interest of the retailer. This agent ensures optimal trade of electricity from the PMC to markets by using the prices of the day-ahead market and weather forecasts.
- In-home agents that represent the interests of the consumer.

In this project, direct control is applied to the heat pump and the micro CHP (i.e. controlling electricity production). Operations of washing machines can be pre-defined and therefore semi-direct control is provided to those appliances (flexibility variable **how**). No other household consumption units are controlled, nor is any price incentive given for general consumption. Each of the three actors is involved in the bidding process (in an automated manner) where after a "balance price" is determined at each moment in time (flexibility variable **why**). This local market takes account of the day-ahead spot market price, balancing market price and local transformer loading and consumer preferences for electricity consumption.

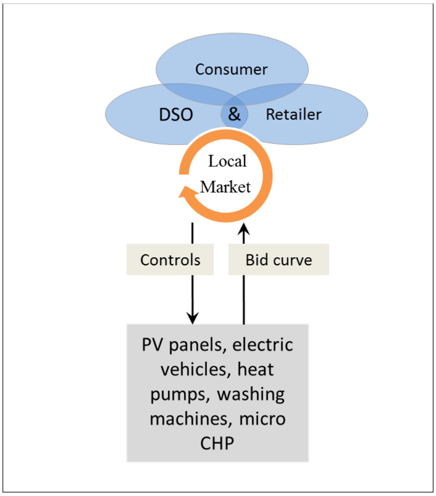

Figure 5.1: Organization of flexibility management in Multi-objective Optimization project "Power Matching City"

5.1.1 Nature of the transactions and number of actors involved

In this case, the retailer, DSO and consumer play an important role in the transactions for flexibility. The IT system acts as a real-time trading platform for local transactions between the different trading agents (DSO, retailer and consumer) who can bid within the local market simultaneously through the PowerMatcher. As there is no central actor making the decisions, the nature of the transactions in this case is therefore horizontal.

5.1.2 Suitability to the retail competition context

Firstly, in this case, the DSO, retailer and consumer take up different roles to those in the traditional retail competition context. In the daily operation of the Multi-objective Optimization project, the retailer, DSO and end user have been permitted to procure flexibility for individual economic objectives locally. However, in the current European retail competition context, markets are only located at the transmission level, not at the distribution level. Traditionally the DSO, retailer and end users do not assume this role and do not have permission to trade flexibility at the local level.

Secondly, an issue exists within PMC for the coordination of flexibility between actors. In PMC, the different interests of the actors in relation to flexibility management have been divided arbitrarily; all agents are given a certain measure of flexibility. Experience has shown that at certain moments in time conflicts can arise in the procurement of flexibility. Often, for instance, one party needs all the available flexibility but can only use its own part from the resident, or two actors would need the flexibility at the same time. Therefore, in PMC, it was only in such periods of conflicting flexibility objectives that the energy supplier assumed the role of deciding who would receive what type of flexibility (DNV GL, 2015). However, in a retail competition context, as in Europe, where end users should be able to choose their supplier, this case could become even more complex as coordination is required between multiple retailers, the DSO and the consumer.

5.1.3 Possibilities for upscaling

The PMC project relates to the approach of nodal pricing, in which the price of every network node reflects both network and supply scarcity (Sotkiewicz and Vignolo, 2006). To make this case possible within the European retail competition model, a readjustment is needed in relation to the roles and responsibilities of actors together with a method for the set-up of local markets, which would allow for multiple retailers to be integrated.

As well as these two important steps, a settling method is also required to locally divide the flexibility between different agents when this is procured simultaneously – also referred to as the coordination problem (Hakvoort and Koliou, 2014). However, it should be noted that this actor could be biased towards specific market objectives (instead of efficient network utilization) when involved in market activities. It is therefore recommended that this party should be a regulated entity, like the DSO. The duties of this actor are to ensure that flexibility is used according to market rules, that harmful interferences between congestion management and balancing are avoided, and that indiscriminatory provision of flexibility is safeguarded (CEDEC et al., 2017). Consequently, the role of the DSO could become more prominent, and therefore the regulation that manages this role of the DSO should become more detailed in relation to flexibility management.

5.2 Case Study 2: Dynamic Pricing

The "Your Energy Moment" is a pilot project in an apartment block and a group of semi-detached houses in the Dutch city of Breda (see Figure 5.2). Under this project, a time-dependent two-hour varying tariff (€/kWh) is presented to the consumer via an in-home energy display (flexibility variable **how**). This final bill includes both a price component of the retailer and of the DSO (flexibility variable **who**). Each of the households owns a PV unit and net-metering takes place for remunerating the PV production. The retail price is based on the price variation in the day-ahead market while the time-dependent transport tariff is a peak-pricing scheme related to the daily network peak hours (Kohlmann et al., 2011) (flexibility variable **why**).

The time-dependent pricing stimulates customers to shift their total household electricity consumption in time. However, to support this load shifting, the customers are equipped with a smart appliance that, if programmed by the consumer, will automatically turn on the "wet appliances", i.e. washing machine, dishwasher and tumble dryer (flexibility variable **what**) at the cheapest moments in time.

5.2.1 Nature of transactions and number of actors involved

In this case, the nature of the transactions in the market is horizontal as the DSO and retailer are both able to present their prices to the end user. However, when compared to the Multi-objective Optimization case, this case represents a less horizontal market arrangement due to the one-directional price signal provided to the end user by the DSO and retailer. The consumer is not involved in the bidding process but is merely exposed to this signal. Therefore in this project the nature of the transactions is horizontal, but in a more reduced form than in the Multi-objective Optimization case.

5.2.2 Suitability to the retail competition context

In the Netherlands and most other European countries, the DSO is obligated to provide non-discriminatory third-party access to flat pricing schemes. Traditional regulation could hamper the time-based pricing from the DSO due to market power risks, especially at points when the distribution price is higher than the retail electricity price. The price signal given by the DSO in this case might lead to discrimination in time and location in the use of electricity. The regulation of DSO price settlement is, therefore, an important conflict with the retail competition model for the DSO.

5.2.3 Possibilities for upscaling

An important adjustment, firstly, is enabling the DSO to provide time-based tariffs and providing regulatory incentives for DSOs to do so. If the DSO is not remunerated to reduce investment expenses by slightly increasing operational costs for the procurement of flexibility, it will remain uninterested in development towards price-based flexibility activation.

Secondly, guidelines are required for the price signals given by the retailer and DSO. These should then be forwarded to the consumer through a settled formula. In order to fit the retail competition context, multiple retailers should be able to provide their specific price signal, which is then combined with the local distribution price. The possibilities for upscaling, in this case, are less difficult than in the Multi-objective Optimization case due to the fact that it is the price signal that activates flexibility, rather than a simultaneous bidding process between multiple actors.

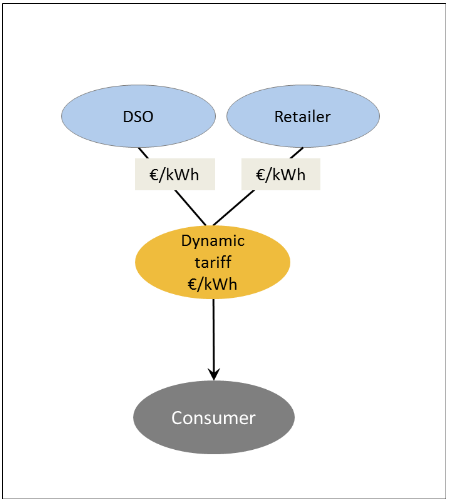

Figure 5.2: Organization of flexibility management in Dynamic Pricing project "Your Energy Moment"

5.3 Case Study 3: Local Aggregator

The Local Aggregator is a case study referring to the project "Energy Frontrunners" (Energie Koplopers in Dutch) in the Dutch municipality of Heerhugowaard.[10] The applied flexibility management method is described as the Universal Smart Energy Framework (USEF).[11] In this project, 240 households have a remotely controlled device installed, through which direct control is applied to specific appliances (flexibility variable **how**) by the local aggregator (flexibility variable **who**). In this project, the aggregator is the Dutch retailer Essent. Essent controls the operation of the heat pumps, electric boilers, fuel cells and PV curtailment (flexibility variable **what**). Besides being the aggregator, Essent is also the balance responsible party (BRP) in charge of trading flexibility on the national balancing markets (**why**). However, in this pilot project, the trading transactions are simulated and do not take place in reality.

The DSO buys flexibility from the aggregator in order to reduce the solar peak from the PV panels and reduce the evening peak consumption in the local distribution network. Eventually, at the end of the month, the (simulated) revenues that have been created from

[10] See https://www.energiekoplopers.nl/contact/ for more information.

[11] See www.usef.info for more information.

trading activities in the balancing market and from network optimization are divided among the participating households (see Figure 5.3).

5.3.1 Nature of transactions and number of actors involved

The aggregator is placed centrally in this case study and trades on behalf of the BRP and the DSO. Due to this central role of the aggregator, the nature of the transactions can be seen as a hybrid, as a single actor is responsible for operations but takes account of the requests of the DSO and BRP. This case study has many similarities with the aggregator Case Studies 1 and 2 in Chapter 4, but this case shows an example of an aggregator which simultaneously takes account of network and supply flexibility at the distribution level.

5.3.2 Comparison with retail competition

Under the pilot project, all the households had the freedom to choose their own retailer, independent of whether or not this retailer was also the actor responsible for the aggregation. When an (independent) aggregator changes the consumption levels of end users which are contracted with other retailers, a compensation mechanism is required to make up for the changes in the balancing responsibility programme (Eurelectric, 2015, 2014).

In this case, the role of the DSO is also different to that in the traditional liberalized model in Europe. As described in the previous cases, the DSO, as a natural monopolist, is generally not incentivized nor allowed to procure flexibility.

5.3.3 Possibilities for upscaling

Firstly, due to the monopoly role of the aggregator, a clear definition of its role and the degree of freedom with regard to the management of flexibility is required. For this aggregator, which could be a regulated party, there should be a clear definition of what transactions are allowed with the DSO and BRP while safeguarding customers' wishes in relation to the direct control of appliances.

Secondly, an important adjustment here is the allowance and incentives for the DSO to procure flexibility. If the DSO is not being remunerated for reducing the investment expenses of the grid by slightly increasing operational costs for the procurement of flexibility, the DSO will remain uninterested in developing price-based activation of flexibility.

Lastly, to enable customers to have a retail choice together with the availability of independent aggregators in electricity markets, specific compensation mechanisms should be set up for retailers affected by adjustments in their customers' consumption by an independent aggregator. This compensation mechanism is needed only when an actor different from the retailing party affects the retailer's programme responsibility through its actions towards end users. For actors that are both retailers and aggregators and trade flexibility in markets through their own end users, their flexibility activation does not have to be compensated through mechanisms, as it has been their own actions that have resulted in flexibility and therefore this is directly internalized in their own overall portfolio.

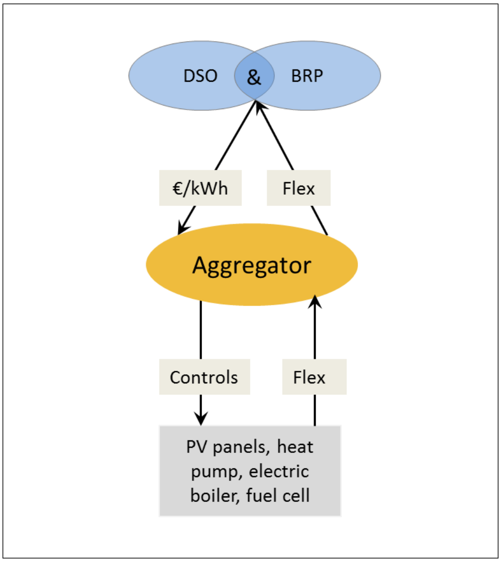

Figure 5.3: Organization of flexibility management in Local Aggregator project "Energy Frontrunners" adapted from (USEF, 2015)

5.4 Case Study 4: Local Integrated Utility

The village of Feldheim (Germany) is an example of cooperation between private households, the municipality and project developers for the management of a decentralized renewable energy system (Energiequelle, 2015). See Figure 5.4 for a conceptual view of the flexibility management in this project. The project has a history of attempts to buy back the grid from the DSO. However, after failed attempts, the village received a subsidy from the European Commission to build its own local electricity network. The entire system is managed by a cooperative, comprised of the retailer, the owner of the electricity network and the manager of flexibility (flexibility variable **who**). The project includes 37 households, two businesses, two local government entities as well as three agricultural enterprises. The cooperative uses direct control (variable **how**) to activate flexibility from a lithium-ion battery storage, biomass plant, wind power plant and solar PV farm (variable **what**). Net production from the PV, wind and biomass is sold back to the grid and is remunerated via a feed-in tariff. The flexibility from the battery storage is being sold for the provision of flexibility services for frequency control, and the operation of the devices is controlled to meet network constraints (Energiequelle, 2015) (flexibility variable **why**).

Many local customers are also shareholders in the cooperative. However, some customers still decided to choose another retailer administratively (probably because they are not part of the cooperative), while the cooperative is still responsible for ensuring overall reliability of electricity supply.

5.4.1 Nature of transactions and number of actors involved

The cooperative, as a single monopolistic actor, takes all decisions regarding the operation of DER locally. The nature of the transactions that take place in the "Feldheim" project are therefore hierarchical in form. There is no involvement of a DSO or retailer as the cooperative is the owner of the local network and responsible for the reliability of supply.

5.4.2 Suitability to the retail competition context

The locally owned and operated electricity system presented in the integrated utility could be seen to conflict with liberalization rules because the network operator is not unbundled from the electricity supply. In theory, local customers in this case are not eligible to choose their supplier.

A risk of this development is that if all customers choose to be administratively contracted to a supplier other than the local cooperative, this could lead to cost recovery problems for the local supplier and eventually to reduced reliability of supply. The end users in this project, however, are shareholders within the cooperative, which acts as an incentive for contracting with the local cooperative. In the long term, if many cooperatives emerged (without local shareholders), there is a risk that all users would only wish to contract with the cheapest retailer available in the country.

5.4.3 Possibilities for upscaling

This project inherently does not provide retail choice, as the local integrated utility is both network owner and supplier of retail services. This goes against the regulations for unbundling of network operations (the monopolistic activities) from supply activities in the retail competition context. In the retail competition context, it is assumed that retail choice will foster efficiency in the sector. In the case of a local integrated utility with local shareholders, however, the drive for efficiency results directly from the community both as owners of the cooperation and end users of its services. This case therefore inherently provides an alternative to retail competition through self-regulation. The possibility for upscaling this case is not particularly straightforward in Europe, as it would require some rethinking of the actual retail competition model set in place. In the European retail competition model, monopolistic utilities have been replaced by retail competition and therefore might compete with the idea of a single utility. However, theoretically, every city or municipality could have a local utility which could be community owned through shareholders, and in that way, ensure cost efficiency through self-regulation for the entire community.

2014).

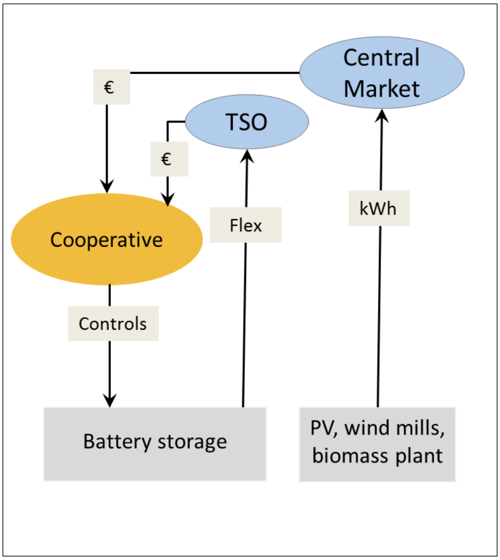

Figure 5.4: Organization flexibility management in Local Integrated Utility project "Feldheim"

5.5 Discussion

The examples presented in this chapter demonstrate the use of flexibility with a (set of) local actor(s) managing the flexibility decentralized from the national electricity system. The case studies show how flexibility is managed, taking account of both the network and market needs of flexibility. In these cases, multiple perspectives are considered for the management of flexibility and therefore the simultaneous time- and location-dependent needs for flexibility are taken into account.

5.5.1 Suitability to the retail competition context

The different case studies provide different consequences in ensuring retail choice for customers, i.e. in relation to the unbundling requirements of the DSO and the integration of multiple retailers. The DSO would not generally be allowed to offer TOU pricing due to the discriminative character that these signals could give to the retailing market parties. Adjusted regulation is required for the DSO to allow for such transactions.

In the Local Aggregator model (Case Study 3) – an independent aggregator changes the consumption levels of flexibility-providing units, but consumers are still free to choose any retailer. Therefore this case does not affect the possibilities for retail competition. However, a compensation mechanism is required to make up for the changes in the balancing responsibility programme that the aggregator makes for the retailers involved (Eurelectric, 2014).

The Dynamic Pricing and Multi-objective Optimization cases represent more technically complex systems for the integration of multiple retailers. Both the retailers and DSOs are involved with the management of flexibility. In these projects, guidelines are required to make sure that multiple retailers are allowed to access a fair part of the flexibility of the end users through direct control (Case Study 1) or present their individual (standardized) pricing schemes to the customer (Case Study 2).

In the Local Integrated Utility case, the cooperative is both owner of the local network and retailer. This, by definition, is not a retail competition model, because no unbundling of the local network and retailer has taken place. Nevertheless, retail choice has still been ensured because end users are eligible to be contracted to other retailers. However, many end users in this case do not choose differently because they are shareholders as well as customers of the local cooperative

5.5.2 Possibilities for upscaling in Europe

The number of actors involved in the management of flexibility ranges from between one and three in the different cases. In the Multi-objective Optimization project, the transactions between the DSO, retailer, and consumer are of a horizontal nature. As the transactions between those actors take place in real time, the Multi-objective Optimization project has the highest level of operational efficiency, but also the highest level of complexity and related transaction costs, especially when integrating diverse retailers within this project (Verzijlbergh et al., 2014). In the Dynamic Pricing project, both the DSO and retailer are involved with flexibility management by means of a time-based price signal. This represents the horizontal nature of transactions, but on a lower scale than that of the Multi-Objective-Optimization project, as the consumer is merely exposed to a price signal rather than being involved in determining it. In the Local Aggregator project, a single actor is responsible on behalf of the DSO and BRP, representing a hybrid nature of transactions. Lastly, in the Integrated Utility Model project, one central actor is responsible for flexibility management, representing a very hierarchical nature of transactions. Figure 5.5 represents the cases conceptually and the nature of the transactions between the different actors.

Lastly, to enable customers to have a retail choice together with the availability of independent aggregators in electricity markets, specific compensation mechanisms should be set up for retailers affected by adjustments in their customers' consumption by an independent aggregator. This compensation mechanism is especially needed when an actor other than from the retailing party affects the programme responsibility of the retailer through its actions from end users. For actors that are both retailers and aggregators and trade flexibility in markets from their own end users, their flexibility activation does not have to be compensated through mechanisms.

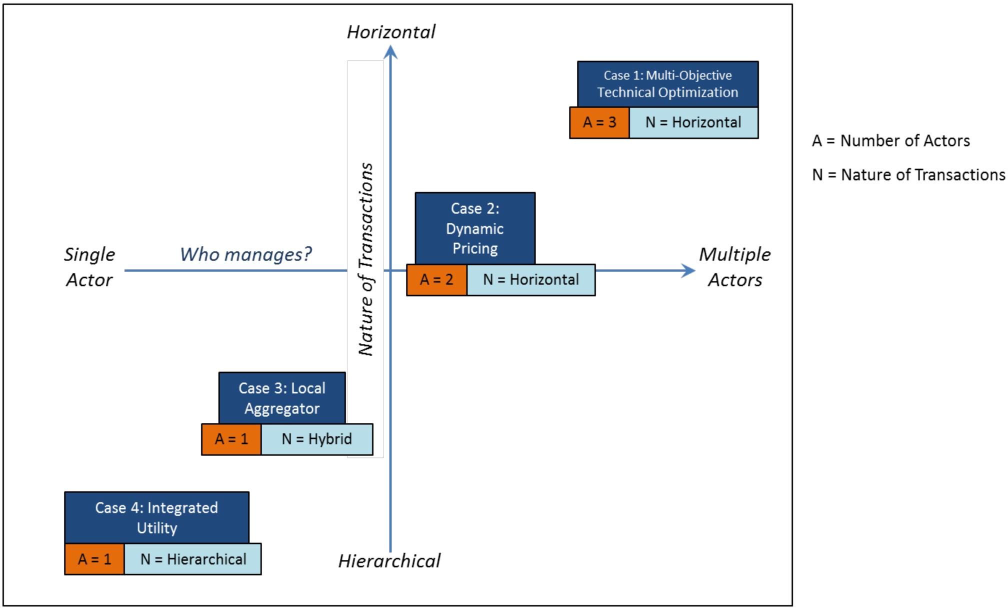

Figure 5.5: Conceptual presentation of cases and nature of transactions

5.5.3 Technical coordination issues

Unlike in Chapter 4, the case studies in this chapter represent high technical coordination between network scarcity and electricity supply through flexibility management. The issues that arise from these case studies are therefore not mainly from a technical nature, but from rather policy, regulatory and economic nature.

5.5.4 Valuation problem

The management of flexibility can serve specific purposes within the system and may eventually create value based on its use in specific markets. In some of the cases, the trading for flexibility took place within already existing markets such as day-ahead and balancing markets. This was the case, for example, with trading of flexibility to align with day-ahead market price variations (in Case Studies 1 and 2) and to trade flexibility in balancing markets (in Case Studies 3 and 4). These arrangements provide monetary value for the traders involved. In some of the other projects presented in this chapter, trading of flexibility has been used to manage network peaks. However, there are currently no market model or incentives to allow for trading of distribution network capacity that will provide monetary value for DSOs in Europe on a large-scale basis.

Such interactions therefore cannot be economically viable without adjusted regulations and market design for DSOs, aggregators and retailers, and possible interactions between them. The issue of monetary value is present particularly for the DSO (of importance in Case Studies 1 to 3), due to the fact that the rationale for the DSO to procure flexibility in Europe is not the most logical when considering the way in which most DSOs are remunerated. Incentive-based regulations (which are used mostly in Europe) motivate DSOs to reduce OPEX and/or CAPEX over time by an efficiency factor. Generally, the costs related to flexibility trading would be considered to be OPEX on which efficiency measures apply. Therefore, it would not be beneficial for the DSO to procure flexibility as this would increase the OPEX. By allowing the costs related to the procurement of flexibility (CAPEX and OPEX) to remain outside the regulatory benchmark, policy makers could support the DSO to utilize flexibility of end users. Overall, the case studies in this chapter show flexibility management not just as a cost efficiency function, but as a more fundamental function combining reliability, sustainability and cost efficiency. This is mostly due to the "greenfield approach" in these cases, in which roles and system functions were able to be defined almost from scratch.

5.5.5 Regulation and scalability

Two points are of interest in discussing the scale at which these cases would suit the European retail competition context and provide possibilities for upscaling. Firstly, to what degree are multiple retailers able to retail their electricity to end users simultaneously? This refers to the possibility of sustaining retail competition in Europe with the chosen arrangement. Secondly, what is the degree of complexity involved with upscaling this methodology for further development in Europe?

For all the projects in this chapter, the role of the DSO as a "trader for electric flexibility" is very different to the one the DSO currently has. For example, in Europe, most DSOs are subject to incentive regulation, which means that their OPEX should decrease by an efficiency factor each year. However, the procurement of flexibility through smart grid solutions can increase the OPEX in time. This, in turn, can counteract the tendency of the DSO to embark on this route. So, to allow for such a role to develop for the DSO, it needs an adjusted regulation for its incentives and possibilities to interact in markets for flexibility.

All the cases except for Case Study 4 (the Integrated Utility project) make it possible for multiple retailers to compete for customers simultaneously. However, the more horizontal the nature of the transactions and the number of actors involved, the more technically complex the requirements need to be for different retailers to compete in such local markets in real time. This is mostly the case for the Multi-objective Optimization approach. The Dynamic Pricing model provides a simplified method for multiple retailers to compete for end users by standardizing the computation for the final dynamic price to the end user. Therefore this is a less complex method than the Multi-objective Optimization approach and more suited for upscaling.

5.6 Conclusions

The case studies in this chapter demonstrate the use of flexibility for a range of new functions. Flexibility management serves next to cost efficiency objectives, also renewable power integration, electricity network usage and supply optimization. These cases can be recognized by technical coordination between network and supply needs of flexibility. In theory, a truly efficient market price in every node of the network would take account of both the supply and network scarcity at each moment in time. Case Study 1, PMC, relates to this approach of nodal pricing, in which the price of every network node reflects both network and supply scarcity (Sotkiewicz and Vignolo, 2006). To make this case possible within the European retail competition model, a readjustment is needed in relation to the roles and responsibilities of actors together with a method for the set-up of local markets, which would allow for multiple retailers to be integrated.

However, the integration of flexibility management for the electricity network and supply does not come without challenges within the context of European retail competition. Firstly, the role of the DSO as a "trader for electric flexibility" is very different to the one the DSO currently has or is allowed to have. Due to their natural monopolistic characteristics, DSOs are subject to price regulation and required to provide fair network access to network users. For example, in Europe, most DSOs are subject to incentive regulation, which means that their OPEX should decrease by an efficiency factor each year. However, the procurement of flexibility through smart grid solutions can increase the OPEX in time. Secondly, the fair access requirements prevent the DSO to present price signals that might discriminate end users based on network capacity from equal access rights. Thirdly, and related to the previous point, there are limitations to possible alternative interaction mechanisms between actors like local markets and new interactive pricing tools.

Improved coordination, however, could take place in several ways, for example, by adding new responsibilities to existing actors (such as for the DSO), and/or introducing new regulation, incentives or markets for existing actors to ensure coordinated network and supply flexibility management (CEDEC et al., 2017). As discussed in the TSO-DSO data management report, it is suggested that the effective use of flexibility is characterized by two main aspects: 1) it avoids harmful interferences between network and supply needs for flexibility; and 2) it supports the non-discriminatory use of flexibility. In each of the cases, except the integrated utility case, this could be theoretically arranged by providing the DSO or the independent aggregator with the roles and responsibilities that satisfy those two aspects in the way flexibility is managed. For example, *ex ante* TOU price settlement for network usage helps to avoid harmful interferences between network and supply needs, while also supporting non-discriminatory use of flexibility by other actors as retailers can internalize those *ex ante* presented network prices in their portfolio scheduling.

6 Assessing the Cost of Flexibility from Flexibility-providing Units

The information in this chapter is based on the paper "Assessing the Costs of Electric Flexibility from Distributed Energy Resources: A Case from The Netherlands", which is under review for the journal Sustainable Energy Technologies and Assessments (Eid et al., 2017).

The previous two chapters presented methods by which electric flexibility could be managed. This chapter presents a method for assessing the explicit costs of flexibility (per kWh) from distinct types of flexibility-providing units. The costs per kWh of provided flexibility can then be compared with the actual prices in the central market, and eventually show what potential possibilities or challenges exist for trading flexibility services as a profitable business. Chapter 7 subsequently presents the potential revenues for electric flexibility trading in two cases that relate to the ones presented in Chapter 4 and 5.

Traditionally, low voltage grids have been designed to transport electricity to users for consumption, and not the other way around. However, because of increased DERs, low voltage grids are increasingly carriers of bi-directional electricity flows and in some cases require extra flexibility in order to cope with the variable production and demand patterns of DERs (Eftekharnejad et al., 2012; von Appen et al., 2013; Walling et al., 2008). With the increasing penetration of solar PV, CHP and EVs, a need arises for electric flexibility, for example, through storage solutions or DR programmes (Denholm and Hand, 2011; Faruqui et al., 2010).

Flexibility management can make the penetration of DERs provide value to the system (Eid et al., 2016d; Koliou et al., 2013; Niesten and Alkemade, 2016). Research has been carried out to calculate the benefits from DR (Codani et al., 2014; Eyer and Corey, 2010; Faruqui et al., 2010; FERC, 2015a; Pudjianto et al., 2007; Xenias et al., 2015). There are many different possibilities for setting up (economic) incentives for the activation of electric flexibility. Some authors have discussed the pool approach and bilateral arrangements for aligning flexibility supply and demand (Eid et al., 2016a; Huang, 2011; Lund et al., 2012; Negnevitsky et al., 2010).

However, in traditional electricity systems, markets are only located at the high voltage level. In those markets, the merit order of traditional, large-scale production units is the deciding factor for defining the marginal price in the market. Such systems do not exist for local distribution networks. However, as has been shown in the previous two chapters, pilot projects do provide insights into the possibilities for these developments (Eid et al., 2016a; Lund et al., 2012; Niesten and Alkemade, 2016).

In order to assess the actual costs of local flexibility provision, it is important to calculate the investment and short-term average costs (STACs) for enabling flexibility from DER technologies. Previous research identified indicators for defining the capital O&M costs of storage units (DOE, 2013). Furthermore, cost and performance assumptions for modelling large electricity generation technologies exist (NREL, 2010). The International Energy Agency (IEA) developed the FAST method (IEA, 2011), a method for quantifying how much variable renewable generation can be integrated within a specific electric system. Previous research has also identified indicators for defining the capital and O&M costs for storage units (DOE, 2013). Other cost calculation methods include the levelized cost of energy (LCOE) and marginal cost approach, which are further described in Section 6.1.

However, research does not provide a unified, comparable metric for determining the STACs of flexibility from small DERs in €/kWh. This chapter aims to fill this gap and presents the costs for the provision of flexibility for different pre-set time durations. The cost perspective is chosen to be an aggregator which could potentially manage the flexibility from those resources and provide this aggregated flexibility in central markets. This perspective is chosen in order to include costs that an aggregator would have to bear (for example, the installation of enabling devices for the provision of electric flexibility), and to exclude costs that would be paid by the end user rather than the aggregator (for example, investment for EVs and solar PV panels). Finally, the costs for each DER technology can be compared with the prices in the balancing and day-ahead markets. In this thesis, Dutch electricity prices have been used as a reference case in the calculations.

In this analysis, a price-taker approach is followed, meaning that any provision of flexibility services does not affect market prices. Furthermore, the flexibility itself could be potentially traded in different markets beyond balancing and day-ahead markets and for different purposes like (local) network congestions. This chapter presents this methodology in order to assist decision-making regarding cost-efficient approaches for the design and operation of flexibility management.

6.1 Cost Calculations for Flexibility

The costs of installing and operating electricity units include both fixed and variable costs. Fixed costs include costs that do not change if the amount of electric flexibility provided increases. These are, for example, the investment costs of the technology. However, variable costs change when the production or consumption output of the unit increases. An example of a variable cost is the fuel cost. The following sub-sections describe the definition of the levelized cost of electricity and marginal cost.

6.1.1 Levelized cost of electricity

The LCOE is a commonly used calculation for comparing the production costs of different electricity-producing units. It is an assessment of the total cost of **building** and **operating** a generation unit over its lifetime, divided by the total energy produced by the unit over that lifetime. This calculation includes all the costs over its lifetime: the investment costs, O&M costs, costs of fuel and capital costs. To evaluate the total cost of production of electricity, the streams of costs are converted to a net present value (NPV). LCOEs can be typically calculated over 20- to 40-year lifetimes, in a unit of €/MWh. It must be noted that the values of LCOEs are highly dependent on assumptions such as capacity factors, economic lifetimes and discount rates. The LCOE can also be seen as the minimum cost at which electricity must be sold in order to break even over the lifetime of the project (Pérez-Arriaga, 2013).

6.1.2 Marginal cost

Marginal costs are a function of both fixed and variable costs and can be defined as the overall change in price when a buyer increases the amount purchased by one unit. This unit, in time, can also be called the marginal unit. It can therefore be expressed as the derivative of the total cost with respect to output (Reneses et al., 2013). Generally, a distinction can be made between short-term marginal cost and long-term marginal cost. Typically the short-term marginal cost of electricity production at the power system level is determined by the variable cost of the marginal generator, i.e. the cost responding to changes in demand at a given time. Given that, in electricity, fuel costs are the main variable cost, marginal costs are found to be the derivative of fuel costs with respect to output, i.e. the amount of electricity produced. In electricity systems, the term ''efficiency'' refers to ensuring that the generators with the lowest marginal costs are dispatched as much as possible.

6.2 Assumptions for Calculating the Flexibility Costs from DERs

The LCOE calculation is of interest in comparing different large units, but requires realistic assumptions about capacity factors for each of the units. The LCOE price combines investment and O&M cost in a price per kWh. These can, however, change and, depending on whether a unit is being used, can reduce or increase significantly. Unlike for the LCOE, the STAC calculation in this chapter does not contain assumptions regarding yearly load factors, but only makes assumptions regarding the maximum flexibility provided in kWh for a unit in timeframes. The calculation here therefore detaches the (kWh-based) STACs from the long-term investment (kW) costs for different flexibility timeframes and technologies. As flexibility costs in central flexibility markets are also based on variable, kWh-based costs, this distinction is made here, leaving the installation costs out of the STAC calculation. Therefore the equivalent annual costs (EACs) of DER flexibility can be seen as a LCOE specified for different event durations (*y)*, at which the entire capacity of the unit is used. The STACs are therefore not based on how frequently the requests for flexibility (flexibility events) take place, but rather on how much energy is delivered within each event duration. In this method, the event durations of 15 minutes, 1 hour, 6 hours and 12 hours are used. This is based on the IEA report, which used similar timeframes — 15 minutes, 1 hour, 6 hours and 36 hours — to categorize the flexibility potential in systems (IEA, 2011). However, the longest timeframe (36 hours) has been reduced to 12 hours for the purpose of this work. It was mostly needed for the flexibility potential of large nuclear and older steam plants that are only able to respond within 36 hours, but is not necessary for smaller DERs, and this has therefore been adjusted.

6.2.1 Comparison between technologies

To make comparison of different technologies possible, an investment capacity of 10 kW is chosen for all the technologies; this refers to a potential flexibility provision per timeframe of 2.5 kWh, 10 kWh, 60 kWh and 120 kWh. The 10 kW capacity serves as a benchmark and could provide power for around seven households in the Netherlands. The investment costs of the technologies are based on one or both of the metrics used (kW and/or kWh). This is due to the different characteristics of the technologies – for example, for battery technologies, values for capacity (kW) and energy (kWh) were needed to provide accurate values of the costs involved by battery size and the charging/discharging abilities of the battery.

6.2.2 Use of terminology for upward and downward flexibility

From a technical perspective, it is possible to provide upward and downward flexibility to the system. In this thesis, upward flexibility refers to the ability of the unit to feed in electricity to the system or to decrease consumption levels. Downward flexibility refers to the ability of electricity to be consumed or stored, or for its generation to be increased. Storage units and demand management approaches are generally able to provide both upward and downward flexibility, while the electricity generation from units like micro CHP is an example of downward flexibility.

6.2.3 Investment perspective

The investment perspective in this chapter is from that of an aggregator. For an aggregator, the use of flexibility can be valuable if specific units are aggregated for market participation. As some technologies are typically invested in by the end users themselves instead of the aggregators, the analysis excludes the costs of investment in technologies like the EV, solar PV and demand appliances. Therefore it is assumed that these are all owned by and *ex ante* paid for by the end user. The aggregator only invests in the enabling devices for flexibility management from those technologies. For all the other technologies in this chapter (batteries, CHPs, power-to-heat, etc.), it is assumed that an aggregator both owns and operates these DERs due to their typical size and the ability to supply multiple households.

6.2.4 Costs for charging and discharging

Another important assumption in this analysis is that for the appliances which have bi-directional possibilities (all battery technologies), the flexibility taken from the device is always given back to the device. This means that if a battery is discharged for flexibility provision, it is charged again at another moment in time. And if a unit is charged for flexibility provision, it would be discharged again at another moment in order to be reset to its default value. This means that all the flexibility taken from the device is also placed back again when possible, at another moment in time, allowing the unit to be returned to its original state. The electricity cost itself is therefore left out of the calculation for DER when storage takes place (e.g. for batteries, demand management and EVs). This makes it possible to compare DERs with different characteristics with each other.

6.2.5 Other cost assumptions

Electricity and gas prices from the Netherlands are used for the cost calculations of the different technologies. For 2016, the average Dutch household electricity price including tax was €0.16/kWh and €0.12/kWh excluding tax. The average household gas price in the Netherlands in 2016 was €0.078/kWh including tax and €0.038 excluding tax. For the 28 Member States of the European Union (EU-28) in 2016, these values were slightly different, with the average household electricity price including tax being €0.20/kWh and €0.14/kWh without tax. The European gas price was €0.062/kWh including tax and €0.047 excluding tax (values are taken from the Eurostat website).[12]

The costs for the different technologies are taken from the Department of Energy (DOE, 2013), the Environmental Protection Agency (Environmental Protection Agency, 2015) and the National Renewable Energy Laboratory (NREL, 2010). An exchange rate of 1.08 \$/€ is used for dollar to euro conversion.[13] To make it possible to compare different technologies, investment is calculated for a capacity of 10 kW, meaning that the electricity flexibility provided per timeframe is 2.5 kWh, 10 kWh, 60 kWh and 120 kWh. Furthermore, the difference between the day- and night-time electricity tariffs has not been taken into account in this analysis. This ensures that the cost differences between different DERs only reflect technology-related costs and not time-dependent price differences.

It is important to note that for the investment costs of storage units, many of the costs are given either on a kW basis, a kWh basis or both. Both terms have been incorporated in the reference work used for this analysis, namely that of the DOE. Therefore, the investment costs for the storage units are a summation of the power capacity costs and energy costs relating to the charging and discharging abilities of the installed unit. With regard to the degradation cost, it is assumed that the amount of energy used during a timeframe is directly related to the length of the timeframe in this analysis, due to the fact that the entire unit capacity is used within a timeframe.

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[12] See webstite of Eurostat http://ec.europa.eu/eurostat/statistics-explained/index.php/Energy_price_statistics#Further_Eurostat_information (Accessed on 28.03.2017).
[13] Based on the 27.03.2017 rate.

6.3 Calculating the Investment Cost of Flexibility-providing Units

The calculation of the investment costs of flexibility-providing units is shown in this section. The calculation starts by defining the EAC, which are the amortized costs per year of owning and operating the asset over its entire lifespan.

For each timeframe *y* and each technology *n*, the investment costs are:

$$I_{n,y} = P_{installed} * I_{cost\ per\ kW} + I_{cost\ per\ kWh} * E_y \quad (1)$$

The investment costs are calculated for the different types of units. For the storage units there is also a kWh-based component part of the total investment cost ($I_{cost\ per\ kWh}$). This kWh-based component is multiplied by the electricity provided in each timeframe (E_y). In this analysis, the power installed is the same for all units (10 kW), and the electricity generated is the same in each timeframe (2.5 kWh, 10 kWh, 60 kWh and 120 kWh). When $P_{installed}$ is set to 1, the costs can be obtained for one kW installed power capacity in each timeframe (*y)*.

To calculate the EACs $EAC_{n,y}$ for the investment $I_{n,y}$ and yearly maintenance cost $C_{maintenance}$ of each technology *n* for its entire lifetime, the following formula is given:

$$EAC_{n,y} = \frac{I_{n,y}}{L} + C_{maintenance} \quad (2)$$

6.4 Calculating the Short-term Average Cost (STAC) for DER Flexibility

There are two specifics for storage technologies that need to be accounted for within the STACs per kWh of flexibility provided. These costs are the losses due to the cost of battery degradation ($C_{degradation_{n,y}}$) and the round-trip efficiency ($E_{roundtrip}$). The cost due to battery degradation is the ratio of the investment costs and the power capacity used per timeframe, and is only applicable to the battery storage technologies (Li-on battery, NaS battery and EV storage). Unlike traditional generation units, these battery storage units have changing STACs, depending on the use of the capacity (in this calculation, depending on the size of the timeframe) due to the degradation cost. The $C_{degradation_{n,y}}$ is then calculated by dividing the investment cost I_n by the maximum amount of cycles per lifetime X_n times the power capacity used per timeframe E_y see below:

$$C_{degradation_{n,y}} = \frac{I_{n,y}}{X_n E_y} \quad (3)$$

The degradation costs are based on the average investment costs and on the maximum amount of cycles that the technology can perform during its lifetime. These costs relate to the charge and discharge cycles of storage units. These cycles are not seen as maintenance costs, as cycling costs cannot be prevented with maintenance. Therefore the degradation costs are costs related to the fact that storage units have a limited amount of possible charge and discharge cycles within a lifetime.

The short-term operational costs are expressed as a €/kWh and are based on the losses in round-trip efficiency (€/kWh), losses in fuel costs (€/kWh) due to the mechanical efficiency of a fuel-consuming unit and degradation costs for battery technologies. The round-trip efficiency indicates the efficiency of a storage technology to recover stored electricity power. It is therefore the ratio between energy recovered and the energy input, and only applies to the storage technologies (Li-on, NaS, flywheel, compressed air energy storage (CAES), EV storage) and the supply management (round-trip efficiency for a PV unit, for example, is 0%, therefore total loss of electricity output).

Given that $E_{roundtrip}$ is the round-trip efficiency of the storage technologies and PV unit), $E_{coefficent}$ is the mechanical efficiency of the fuel-consuming units without storage capabilities, $C_{variable\ O\&M}$ the variable O&M cost and, lastly, $C_{degradation}$ is the degradation cost for electrical storage technologies. Then, the $STAC_{y,n}$ for each event duration *y* and each technology *n* is calculated as:

$$STAC_{y,n} = \left(1 - E_{roundtrip}\right)C_{fuel} + \frac{C_{fuel}}{E_{coefficent}} + C_{variable\ O\&M} + C_{degradation} \quad (4)$$

Note, in this formula:

- $\left(1 - E_{roundtrip}\right)C_{fuel}$ applies to all technologies with storage capabilities and supply management. Therefore, C_{fuel} refers to the electricity cost per kWh for those units (Battery Li-on, Battery NaS, flywheel, CAES, EV storage and supply management).
- $\frac{C_{fuel}}{E_{coefficent}}$ applies to the fuel-consuming units without storage capacity. C_{fuel} here refers to the gas costs for the gas turbine, micro turbine, micro CHP (fuel cell) and electricity cost for the activation of the power-to-heat technology. These costs have not been taken account of for the storage technologies (battery storage) and demand management with the ability to provide bi-directional flexibility. It is assumed that for those types of flexibility-providing units the flexibility provided to the system is being placed back at another time and therefore this would net out the electricity cost part in the STAC calculation.
- $C_{variable\ O\&M}$ applies to all technologies except for EV storage, supply management and demand management. The dataset that was used in this study did present variable costs for those technologies.
- $C_{degradation}$ applies only to the battery storage technologies: NaS, Li-on and EV storage.

6.4.1 Results

This section presents the calculation of the installation costs and $STC_{y,n}$ for diverse DERs. The analysis includes: battery Li-ion, battery NaS, flywheel, CAES, EV storage, gas turbine, micro turbine, fuel cell CHP, power to heat, renewable energy source (RES) curtailment and demand management.

Table 6.1 and Figure 6.1 present the upfront investment costs in euros for each of the technologies per kW installed, and if they were required to supply flexibility in 15-minute, 1-hour, 6-hour or 12-hour time-lengths.

		EVENT DURATION			
Direction	***Technology NPV (€/ kW installed)***	***15 minutes***	***1 hour***	***6 hours***	***12 hours***
↑↓	*Battery Li-ion*	3047	11194	65509	130687
↑↓	*Battery NaS*	1458	4839	27380	54429
↑↓	*Flywheel*	1659	2474	7905	14423
↑↓	*CAES*	n/a	1119	1282	1477
↑↓	*EV storage*	674	674	674	674
↑	*Gas turbine*	n/a	2444	2444	2444
↑	*Micro turbine*	3693	3693	3693	3693
↑	*Fuel cell CHP*	n/a	n/a	62462	62462
↑	*Power to heat*	2580	3802	11949	21726
↓	*RES curtailment*	674	674	674	674
↑↓	*Demand management*	674	674	674	674

Table 6.1: Investment costs for each technology in €/kW installed capacity

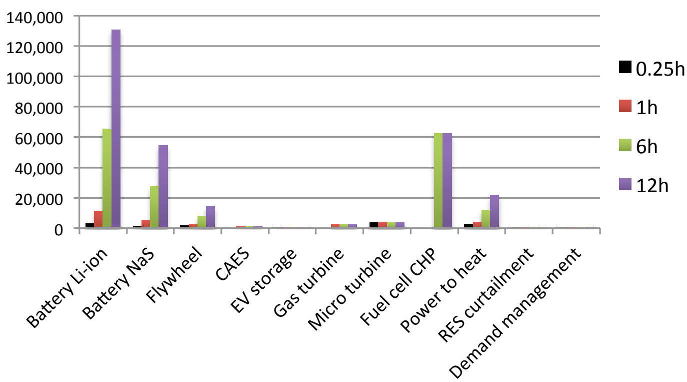

Figure 6.1: Investment costs for each technology in €/kW

Figure 6.1 shows that the storage technologies (battery Li-on and battery NaS), flywheel and power-to-heat technology have increasing investment costs with increasing length of flexibility event timeframes. This is because the cost of supplying the energy significantly increases the (battery) storage costs. However, the costs of EV storage are initially very low, as only upfront investment of the demand management device is presented. The EV itself is invested in by the end user. Alternatively, CAES, EV storage, gas turbine, micro turbine, supply and demand management show similar costs when the energy output increases for longer timeframes. Table 6.1 shows that no values are provided for the 15-minute timeframe for the fuel cell CHP and CAES. This is because the start-up time of the fuel cell CHP is 3 hours and that of CAES is 10 minutes, and therefore these technologies would not be flexible enough to provide electric flexibility in the 15-minute timeframes (for the fuel cell CHP, this inflexibility is also the case for the 1-hour timeframe).

Table 6.2 and Figure 6.2 below present the STACs for each technology per kWh of electricity provided. It can be seen that, for short-term purposes (15-minute flexibility), the costs of EV flexibility are very high. This is because, in this calculation, the replacement of a Tesla battery with a maximum of 5,000 cycles per lifetime and a price of $12,000 for replacement, is taken into account.[14] If the aggregator manages flexibility for only short-term purposes (say, 15 minutes), the price of the flexibility provided (and the related losses due to battery degradation) per kWh becomes very high.

However, the battery technologies (Li-ion, NaS and EV) have decreasing STACs when used in longer timeframes. This is because the degradation costs decrease when the technology is used for provision of larger volumes of flexibility. Nevertheless, storage remains an expensive option and only becomes interesting for medium-term usage. Unlike the storage technologies, the CAES, flywheel, gas turbine, fuel cell, micro turbine, demand and RES curtailment have flat costs per kWh for the different timeframes.

[14] Based on: https://electrek.co/2016/02/26/tesla-vertically-integrated/

Direction	Technology STC (€/kWh)	EVENT DURATION			
		15 minutes	1 hour	6 hours	12 hours
↑↓	*Battery Li-ion*	0.522	0.323	0.268	0.262
↑↓	*Battery NaS*	0.550	0.266	0.187	0.179
↑↓	*Flywheel*	0.029	0.029	0.029	0.029
↑↓	*CAES*	n/a	0.075	0.075	0.075
↑↓	*EV storage*	1.054	0.272	0.055	0.033
↑	*Gas turbine*	0.272	0.272	0.272	0.272
↑	*Micro turbine*	0.324	0.324	0.324	0.324
↑	*Fuel cell CHP*	n/a	n/a	0.206	0.206
↑	*Power to heat*	0.084	0.084	0.084	0.084
↓	*RES curtailment*	0.160	0.160	0.160	0.160
↑↓	*Demand management*	0.000	0.000	0.000	0.000

Table 6.2: Short-term average cost for each technology in €/kWh

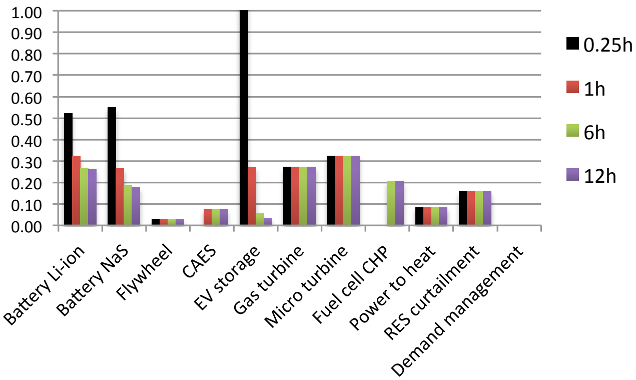

Figure 6.2*: Short-term average cost for each technology in €/kWh*

For RES curtailment, mainly related to PV curtailment or other renewable energy source (like micro wind) curtailment, the costs are directly related to the Dutch average electricity price because it is assumed that owners of PV units are remunerated by a net-metering method. This means that electricity production is reduced from consumption values. Therefore, in this calculation, curtailed production makes the short-term cost equal to the electricity price of €0.16/kWh.

6.5 Discussion

This chapter presents a method for quantifying the costs of flexibility from DERs. For battery technologies, the aspect of degradation costs is included. A number of issues noted in the following sections should be taken into account for the cost calculation method used in this chapter. These are the effects of data availability of cost prices, the costs of upward and downward flexibility and the opportunity costs.

6.5.1 Cost data dependency

The cost calculations in this chapter are based on publicly available information on the costs of DERs. However, most of the data is from reports dating from 2010, 2013 and 2015 (see Annex I). It is expected that the costs of the technologies decrease through economies of scale in production, technical developments and increasing market demand for those DERs. Therefore the costs calculated are an indicator of where the costs could be and how the DERs' costs relate to each other. However, it is expected that by the date of publication of this thesis the costs will be lower than presented in this chapter.

6.5.2 Upward and downward flexibility costs

For the storage units, the assumption is made that flexibility taken from a device, is also replaced at another point in time, to make cost comparability possible based on technology-related costs. In this calculation, the electricity price is assumed to be fixed for households. Therefore this price has not been included in the cost calculation for the STACs of technologies where the status would be "set back" after the flexibility provision. However, this work could be complemented by incorporating specific costs for upward and downward flexibility for each technology.

6.5.3 Opportunity cost

This study takes account of the technical costs of activating flexibility from DERs. However, besides the technical costs (such as those of fuel, investments and O&M), there might also be socio-economic costs involved with the activation of flexibility, i.e. the opportunity cost. Opportunity cost is the cost that would be made if the flexibility was not provided if the unit instead served another purpose – for example, when a taxi EV is used to drive and transport a passenger instead of providing flexibility to the system. If such an opportunity cost is taken into account, the value of upward and downward flexibility could be very different and even more time dependent, making the cost values strongly context dependent. This is also the case for demand management, which in this case shows a cost of €0/kWh. This is therefore replaced with the specific context-dependent opportunity cost of uninterrupted use of a device.

A similar issue arises for the opportunity cost of a solar panel. When this unit is curtailed, potential income may be forgone, thereby creating an opportunity cost. It could be interesting to analyse the profitability of flexibility not only from a techno-economic perspective but also from a socio-economic perspective. However, it must be noted that values of opportunity costs are very situation dependent and could therefore reduce the ability to generalize results.

6.6 Conclusions

This chapter presents a cost calculation method to calculate the investment costs of DERs and the costs per kWh of electric flexibility provided in 15-minute, 1-hour, 6-hour and 12-hour timeframes. To compensate for the differences in calculations between technologies (technologies with and without a kWh-based investment component), a fixed installed capacity of 10 kW is chosen, leading to an energy output of 2.5 kWh, 10 kWh, 60 kWh and 120 kWh for each of the respective timeframes.

First of all, it can be seen that not all technologies are technically able to provide electric flexibility in very short timeframes. The fuel cell CHP and CAES, for example, have a start-up time of 3 hours and 10 minutes and therefore are not able to provide flexibility in the shortest timeframes.

In the calculation of investment costs, account has only been taken of the costs that an aggregator would invest upfront. For example, the costs of the EV are not included because it is assumed that the EV is owned by the end user. Therefore only the demand management device on the EV charging station is considered as an upfront investment for the aggregator.

Furthermore, the upfront investment costs for all of the technologies are the same for each of the timeframes, except for the storage technologies and power-to-heat technologies. This is due to the increased fixed cost related to battery storage (or heat storage) if the required electric energy output increases.

For the STACs of the flexibility provided, all the costs that the aggregator would assign to the owner of the EV have been included. This therefore includes the degradation costs of the EV battery when providing electric flexibility. It can be observed that the flywheel technology and demand management present very low costs per kWh of flexibility provided (€0.029 and €0/kWh). However, it is important to note that for demand management, the calculated STACs for providing electric flexibility might be higher than €0/kWh. As this would result in a highly context-dependent value, it remained at €0/kWh. It is recommended that future research should perform a device-specific analysis of short-term demand management (opportunity) cost.

7 The Effects of Techno-institutional Design on Revenues from Flexibility Management

The information in this chapter is based on the paper "Assessing the Costs of Electric Flexibility from Distributed Energy Resources: A Case from The Netherlands", which is under review for the journal Sustainable Energy Technologies and Assessments (Eid et al., 2017).

The previous chapter presented an approach for quantifying the STACs of flexibility and the values for DERs. This chapter presents the relative costs of flexibility for each of the DERs compared to the prices in the central balancing and day-ahead markets. Relating to Chapters 4 and 5, this chapter presents the potential revenues for electric flexibility trading in two cases, i.e. an aggregator trading in the flexibility market and a retailer trading flexibility in the day-ahead market. It is then possible to analyse which DERs, in which market, would provide the most promising business case.

7.1 Revenues for an Aggregator Trading in the Balancing Market

The first analysis presents the outcomes of an aggregator trading flexibility in the balancing market. Figure 7.1 presents this in the techno-institutional framework. In this framework, it can be seen that the aggregator (flexibility variable **who**) can manage a set of DERs (flexibility variable **what**) to trade in the balancing market (flexibility variable **why**) through direct control (flexibility variable **how**). In this case we assume that the DERs that can be managed are those presented in Chapter 6.

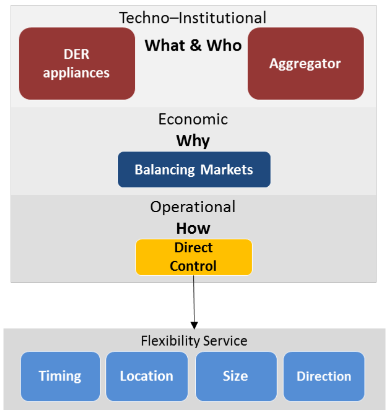

Figure 7.1: Techno-institutional design of an aggregator trading DER flexibility

The balancing markets are organized 15 minutes before real time and require either upward or downward flexibility for 15-minute timeframes. Table 7.1 shows that upward flexibility is priced higher than downward flexibility (the average price of upward flexibility is €0.06/kWh versus €0.02/kWh for downward flexibility). The upward flexibility even pays prices above €0.30/kWh at some points. In 2016, peak prices higher than €0.30/kWh occurred 658 times, based on 2016 data.

Dutch Balancing market prices in 2016	*In €/kWh*
Max. upward flexibility price	0.54
Average upward flexibility price	0.06
Total price frequency above 0	17,987
Frequency of price above 0.30	658
Frequency of price above 0.45	2
Max. downward flexibility price	0.07
Average downward flexibility price	0.02
Total price frequency above 0	18,280

Table 7.1: Overview of balancing market prices in 2016 for 15-minute timeframes[15]

Table 7.2 shows what the yearly revenues would be if the prices in the balancing markets were deducted by the STACs of each DER. In the table, upward flexibility refers to increased production or decreased demand, while downward flexibility refers to a decrease in production or increased demand. It is only for the flywheel technology, micro turbine and demand management that revenues can be obtained in the balancing market. For the battery technologies (Li-Ion, NaS and EV storage) the costs are too high to provide interesting yearly revenues from participation in the balancing markets. Furthermore, the gas turbine and CAES are not flexible enough to provide balancing services.

	Technology STC (€/kWh)	***15 minutes***	***Revenue for upward flex (€/kWh)***	***Revenue for downward flex (€/kWh)***
↑↓	Battery Li-ion	0.442	Not profitable	Not profitable
↑↓	Battery NaS	0.466	Not profitable	Not profitable
↑↓	Flywheel	0.025	607	23
↑↓	CAES	n/a	Not flexible	Not flexible
↑↓	EV storage	0.893	Not profitable	Not profitable
↑	Gas turbine	n/a	Not flexible	Not profitable
↑	Micro turbine	0.275	17	Not profitable
↑	Fuel cell CHP	0.174	Not flexible	Not flexible
↓	Power to heat	0.071	Not possible	Not profitable
↑	RES curtailment	0.136	Not possible	Not profitable
↑↓	Demand management	0.000	1107	397

Table 7.2: Yearly revenues for upward and downward flexibility based on 201 values for 15-minute timeframes; authors compilation from 2015 data of Dutch TSO Tennet balancing market in €/kWh[16]

[15] See the Tennet website for historical data:
http://www.tennet.org/english/operational_management/export_data.aspx

Investment costs for flywheel technology are €1659/kW for the 15-minute flexibility timeframe. For this installed capacity, the flywheel would provide €630 revenue per kWh per year (€607 for upward and €23 for downward flexibility). This investment would break even after five years (1659/607 = 3, see Tables 7.3 and 7.4). With demand management, the investment costs per kW are €674, and break-even would take place after around only five months (674/1504 = 1.6). However, the assumption is that all the balancing events are exploited and this is probably not the case for a normal household or consumer. The aforementioned values are based only on investment costs and STACs and exclude present value of cash flows.

	Technology investment cost (€/kW)	***15 mins***	***Expected technology lifespan in years***	***Yearly revenues (upward flex)***	***Yearly revenues (downward flex)***	***Total revenues***	***Break even in number of years***	***ROI[17] over technology lifespan per kW***	***ROI per year per kW***
↑↓	Battery Li-ion	3047	10	x	x	x	x	x	x
↑↓	Battery NaS	1458	12	x	x	x	x	x	x
↑↓	Flywheel	1659	15	607	23	630	3	7,446	496
↑↓	CAES	n/a	30	x	x	x	x	x	x
↑↓	EV Storage	674	30	x	x	x	x	x	x
↑	Gas turbine	n/a	30	x	x	x	x	x	x
↑	Micro turbine	3693	30	17	x	17	221	-3,193	-106
↑	Micro CHP (fuel cell)	n/a	30	x	x	x	x	x	x
↓	Power to heat	2580	15	x	x	x	x	x	x
↑	RES curtailment	674	30	x	x	x	x	x	x
↑↓	Demand management	674	30	1107	397	1504	0.45	32,540	1,085

Table 7.3: Break-even points of DER with trading in the balancing market, energy prices including taxes

[16] See the Tennet website for historical data: http://www.tennet.org/english/operational_management/export_data.aspx . The data used for this paper is based on a spring, winter, autumn and summer week in 2015.

[17] ROI stands for Return on Investment

	Technology investment cost (€/kW)	*15 mins*	*Expected technology lifespan in years*	*Yearly revenues (upward flex)*	*Yearly revenues (downward flex)*	*Total revenues*	*Break even in number of years*	*ROI over technology lifespan per kW*	*ROI per year per kW*
↑↓	Battery Li-ion	3047	10	x	x	x	x	x	x
↑↓	Battery NaS	1458	12	x	x	x	x	x	x
↑↓	Flywheel	1659	15	770	336	1106	1	9,899	660
↑↓	CAES	n/a	30	x	x	x	x	x	x
↑↓	EV Storage	674	30	x	x	x	x	x	x
↑	Gas turbine	n/a	30	x	x	x	x	x	x
↑	Micro turbine	3693	30	198	x	198	19	2,245	75
↑	Micro CHP (fuel cell)	n/a	30	x	x	x	x	x	x
↓	Power to heat	2580	15	x	x	x	x	x	x
↑	RES curtailment	674	30	x	x	x	x	x	x
↑↓	Demand management	674	30	1107	397	1504	0	32,540	1,085

Table 7.4: Break-even points of DER with trading in the balancing market, energy prices excluding taxes

7.2 Revenues for a Retailer Trading in the Day-ahead Market

The second analysis presents the outcomes of a retailer trading flexibility in the day-ahead market. Figure 7.2 presents this organization in the techno-institutional framework. This shows that the retailer (flexibility variable **who**) can manage DERs (flexibility variable **what**) to trade in the day-ahead market (flexibility variable **why**) through price incentives (flexibility variable **how**).

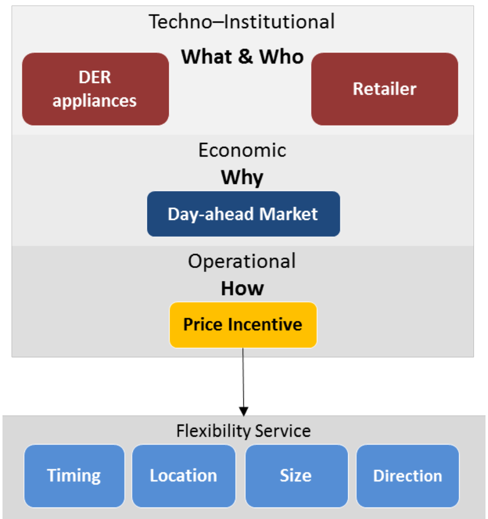

Figure 7.2: Techno-institutional design of a retailer trading DER flexibility

The day-ahead average monthly market price ranges between €25/MWh to €50/MWh (see Annex I). This refers to a range of around €0.03/kWh to €0.05/kWh (see Table 7.5). In this analysis, the average monthly price is assumed to take place on a daily basis (for both work and week days) and takes place once a day for a timeframe of one hour. The results of this analysis are visible in Table 7.6. As can be seen, this reflects mostly negative or minimal revenues in trading flexibility for most DERs. Only demand management and the flywheel technology might present some trading opportunities (€3 and €13 per kWh per year), but still with very little yearly income.

	Jan	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*
€/MWh	50.77	43.06	34.52	25.32	27.19	32.59	33.08	28.36	32.85	38	42.85	43.49
€/kWh	0.051	0.043	0.035	0.025	0.027	0.033	0.033	0.028	0.033	0.038	0.043	0.044

Table 7.5: Monthly average day-ahead market in APX-ENDEX based on April 2016–March 2017

	Technology STC (€/kWh)	*1 h*	*Yearly revenue per for upward flex (€/kWh)*
↑↓	Battery Li-ion	0.323	Not profitable
↑↓	Battery NaS	0.266	Not profitable
↑↓	Flywheel	0.029	3
↑↓	CAES	0.075	Not profitable
↑↓	EV storage	0.272	Not profitable
↑	Gas turbine	0.272	Not profitable
↑	Micro turbine	0.324	Not profitable
↑↓	Fuel cell CHP	0.206	Not profitable
↓	Power to heat	0.084	Not profitable
↓	RES curtailment	0.160	Not profitable
↑↓	Demand management	0.000	13

Table 7.6: Short-term average cost of DER flexibility, marked presenting the interesting options for trading in the day-ahead market

As well as the STACs, it is important to take account of the investment costs for the technologies when analysing returns on investment. For both the flywheel technologies and demand management the return on investment (ROI) would be negative, with -€1,618 as a result for the flywheel technology and -€280 for demand management. This does not provide an attractive investment opportunity for the retailer solely trading in the day-ahead market.

7.3 Discussion

This chapter presents the possible revenues obtained in the balancing and day-ahead markets with flexibility provision from DER, based on the cost calculations in Chapter 6.

This section raises a few points of discussion. First of all, the assumptions that underpinned the cost analysis in Chapter 6 apply here as well. These relate firstly to the data sources used for calculating the investment and the STACs of different DERs. It is expected that costs decrease over time and therefore the costs presented in this chapter are more conservative.

For demand management, the STACs have been set to zero. However, in reality, there are short-term costs related to demand management, such as the opportunity costs if a specific device was to operate without interruption. Other costs related to the STACs for demand management could be device-related costs and IT costs. When the opportunity cost is taken into account for each specific appliance managed, this is expected to significantly reduce the calculated revenues from demand management.

Furthermore, the devices' related STACs are dependent on the electricity and gas prices considered. If the gas price excluding tax was used, the profitability of the gas turbine and micro turbine would be significantly improved – from providing a negative ROI towards breaking even after 19 years with a ROI of €2,245.

Lastly, very limited data was available for the day-ahead market and therefore the actual results are also conservative. Only average monthly prices for the day-ahead markets were used instead of the actual prices in 2016. It is assumed that this price is available for one hour each day in each respective month. The analysis resulted in negative results for all technologies.

It is important to note that, with a price-based signal, the actual flexibility provided by an end user or device is not ensured. Therefore, for the retailer, this trading opportunity requires larger price margins. Consequently, the consumer would be fined for the flexibility not provided through a higher price. Therefore a price-based signal moves part of the price risk from the retailer to the end user. However, the system risk remains with the party wanting to initiate the load adjustment.

7.4 Conclusions

This chapter presented the revenues that can be obtained through two different techno-institutional structures for flexibility management. One presented the possible revenues through trading in the balancing market, and the other in the day-ahead market. A first conclusion is that the revenues in the balancing market are significantly higher for most of the technologies analysed than the revenues that can be obtained in the day-ahead market. The most interesting options from a short-term cost perspective are demand management and flywheel technology.

Flywheel technology would break even very quickly – after just three years. The most profitable, from a ROI perspective, would be demand management and flywheel technology, with a potential ROI of €32,000 for demand management and €7,446 for the flywheel technology over its entire technology lifespan. The revenues are based on the assumption that all trading opportunities are exploited. Trading opportunities are considerably less interesting in the day-ahead market compared to the balancing market. The average prices in the day-ahead market in the Netherlands range from €25/MWh to €50/MWh (based on monthly averages of APX-Endex). This refers to a range of €0.02 to €0.05 /kWh. Income is only present for demand management and the flywheel technology, but is not enough to recover investment costs.

Some assumptions have been made in this analysis. For demand management, the STACs have been set to zero. However, in reality, there are short-term costs related to demand management, such as the opportunity costs if a specific device operated without interruption. Other costs related to STACs for demand management could be device-related costs. In short, it can be stated that if the STACs for demand management (which could be the opportunity cost or another device-specific cost) are lower than the retail price of €0.16 per kWh, and the revenue of performing demand management is higher than these costs per kWh, it is economically viable to perform demand management.

However, it is important to note here that the ROI does not take account of the other uses of the flexibility-providing units besides flexibility provision. For example, the flywheel technology could also be used for storing local renewable power for power provision throughout the day. These revenues have not been taken into account in the calculations due to their situation-specific nature. Therefore the ROI is not reflective of the actual return of the installed unit, but only shown here with regard to the use of the unit for flexibility provision in markets only.

Furthermore, the devices' related STACs are dependent on the electricity and gas prices considered. If the gas price excluding tax is used, the profitability for the micro turbine would be significantly improved to a 19-year break-even point and a ROI of €2,245. When tax is exempted, the flywheel technology would break even only after two years with a ROI of €7,680. Tax exemptions would therefore have a significant impact on the economic viability of technologies.

8 Conclusions and Recommendations

8.1 Conclusions

The European policy focus on smart grids implies their development as an indispensable part of the future power system. However, smart grids remain ambiguous and are used extensively for many diverse developments in the electricity sector. Existing research frequently captures smart grids from a mono-disciplinary perspective: technical, economic or social. This work aims to contribute to the literature by presenting smart grids from a techno-institutional perspective. In short, this thesis presents various smart grid cases via a techno-institutional framework, and provides insights into the potential revenues resulting from flexibility management in smart grids.

8.1.1 The techno-institutional design of flexibility management

The activation of electric flexibility in smart grids receives special attention in this thesis. Electric flexibility enables the benefits from smart grids to be available to the entire electricity value chain: electricity production, transportation and consumption. Electric flexibility can be defined as a power adjustment achieved at a given moment, for a given duration, from a specific location within the network. It results from the response of electricity consumers, producers and those that are both, for example, to price or direct control signals. Flexibility management in this thesis is the techno-institutional organizational arrangement required to enable the management of electric flexibility at the distribution grid level. More specifically, it is the application of four flexibility management variables, i.e. the division of responsibilities (**who**) for specified management of flexibility of appliances (**what**) by specific means (**how**) and for specific reason in the system (**why**), plus two organizational variables, i.e. the **number of actors** involved and the **nature of transactions**. The framework presented in this thesis supports the common understanding between actors with regard to the roles and responsibilities for flexibility management in a smart grid.

8.1.2 Technical coordination and economic valuation issues

Using the techno-institutional framework, different organizational models have been identified from eight smart grid case studies. The case studies illuminate two major issues that emerge in the techno-institutional design of smart grids i.e. the **technical coordination** and **economic valuation** issues.

The technical coordination issue relates to the fact that the network and market needs for flexibility in European electricity systems are not naturally aligned. This disconnection appears due to the fact that electricity markets in Europe's power systems are placed centrally within an electricity system (at the wholesale level), while network congestions can take place at any line of the distribution and/or transmission network, while not being incorporated in market signals. Due to the disconnection of the central market and the local network needs of flexibility, the cases which adhere to this distinction between network and market do not ensure technical coordination between market and network capacity needs for flexibility. As a consequence, the electricity supply and network needs for flexibility can contradict each other at certain moments in time when, for example, high penetration of low-cost renewable electricity may result in local network congestions. Proper technical coordination would ensure that both network capacity and market supply scarcity signals are incorporated into the flexibility management design. This could be done, for example, through price incentives, regulation or through new market design with, for example, nodal markets.

However, cases in which flexibility management shows high technical coordination between network and market needs present trade-offs with regard to economic viability. Such technically complex projects lack a sound business model for operating within the current European regulatory context. Of the four models analysed, the Local Aggregator Model and the Dynamic Pricing Model could be easiest upscaled with multiple retailers, as these projects provide a standardized method of integrating multiple retailers. It can be seen that in most projects, flexibility management is mainly used to reduce the costs of the actors involved (efficiency improvement) and not to cover a fundamental need in the system for more flexibility.

8.1.3 Costs and revenues for flexibility management

This thesis presents a method for quantifying the costs of flexibility from flexibility providing units. The following technologies have been analysed: battery Li-ion, battery NaS, flywheel technology, CAES, EV storage, gas turbine, micro turbine, micro CHP fuel cell, power to heat, RES curtailment and demand management.

For battery technologies, the issue of degradation costs is included in the calculation of the short-term average costs (STACs). Several assumptions had to be made to make comparison possible along a range of flexibility providing units. Firstly, a fixed investment amount of 10 kW for each of the technologies, and secondly, different flexibility timeframe lengths were presented (15 minutes, 1 hour, 6 hours and 12 hours). This was important because some technologies have increasing investment costs with larger energy outputs (mainly the storage technologies).

An important point is that all the battery technologies have STACs above €0.30/kWh for the 15-minute timeframes and therefore are not profitable choices for flexibility provision in balancing markets. The analysis shows that the EV is very expensive for very short flexibility needs in the system (below 30 minutes) if the battery degradation costs of short-term flexibility provision are included.

The lowest STACs were for demand management (€0/kWh) and flywheel technology (€0.03 ct/kWh) in the short timeframe of 15 minutes. The fuel cell CHP and gas turbine were not able to provide flexibility for such a short timeframe due to the longer start-up time of these technologies. Based on one-year data of the balancing market in the Netherlands, the costs per kWh for the different technologies have been compared with the prices in the balancing market. Only demand management and the flywheel technology have resulted in profitable incomes from revenues in the balancing markets. However demand management requires future discussion (see the next section). It is only for those technologies that the balancing market appears to be an interesting option for the trading of flexibility. The ROI could potentially be around €7,000 to €32,000, assuming that all balancing events in the markets would be exploited. However, it is important to note here that the ROI does not take account of the other uses of the flexibility-providing units besides flexibility provision. For example, the flywheel technology could also be used for storing local renewable power for power provision throughout the day. These revenues have not been taken account of in the calculations due to their situation-specific nature.

Trading opportunities are considerably less interesting in the day-ahead market. This is because the average price ranges from €0.02 to €0.05/kWh in the Dutch day-ahead market, which is much less than the STACs of most DERs analysed. Therefore trading in day-ahead markets would not be interesting for any of the technologies at this moment and results in negative outcomes.

It is important to note that the coordination problem would still become a potential issue in the above examples of flexibility trading in the balancing and day-ahead markets. If market mechanisms were to allow for aggregated trading of flexibility from all end users, this could lead to local network congestions at moments when the balancing market price for flexibility is high.

8.1.4 Demand management: cost assumptions

From a theoretical point of view, the short-term cost involved in demand reduction is zero, because the customer does not have to incur costs with activation of such flexibility. For demand management therefore, only an upfront investment, and no STAC, has been taken into account. However, in reality, there are certainly short-term costs related to demand management – for example, the opportunity cost if a specific device operated without interruption. Other costs related to STACs for demand management, could be device-specific costs due to interrupted usage. In short, it can be stated that if the STACs for demand management (which could be the opportunity cost or another device-specific cost) are lower than the retail price of €0.16 per kWh in the Netherlands (or €0.20 per kWh as the European average electricity price) and the revenue of performing demand management is higher than these costs, then it is economically viable to perform demand management for trading in markets.

8.1.5 Transitioning towards electric flexibility as a critical function

In the cost analysis presented, and in most of the case studies in this thesis, the perspective on flexibility management is that of cost efficiency in the context of the design of the current market. This means that flexibility management is used as a method for reducing costs for the actors involved using existing market models.

However, it is questionable whether this perspective would also suit the technical context if the electricity is mostly produced by renewable sources. This could be the result of high penalties for carbon emissions, financial incentives for renewable sources and increased social pressure to move towards a low carbon economy. Each of these motives provides a different context for electric flexibility, resulting most probably in flexibility price incentives and flexibility integration into market models or existing regulation. A higher demand for flexibility would result in a higher price for flexibility, creating an attractive business case for aggregators, retailers and individuals for owning and operating distributed energy resources (DERs).

It is important to note therefore that the cost analysis presented fits the current context, but not a future context in which balancing market prices might increase together with day-ahead and intraday market prices for electricity. Increased introduction of renewables in the coming years could lead to a system with reliability issues. It can be argued that flexibility management has a positive business case only if there are reliability issues (like supply deficiencies). Under such a system, it is expected that electric flexibility would serve objectives of system reliability instead of efficiency only and therefore increasing viability of distributed energy resources.

8.1.6 Generalization of the techno-institutional operational framework

The operational framework in this thesis may also be useful for other infrastructure-based sectors such as telecommunication, gas and transportation. It is important to note the difference between the organization of responsibilities for **fundamental functions** and **efficiency-improving functions** within a system.

The fundamental functions refer to functions that directly affect overall system performance. An example of a fundamental function in the electricity system is electricity system operation. Fundamental functions are the backbone of the processes within the system at stake. If, at any moment in time, the system operation is not well managed by the transmission system operator (TSO), this would result in catastrophic performance for the entire system. Scholten and Künneke call these functions “critical functions”(Correljé et al., 2014; Finger et al., 2005; Knops, 2008; Künneke, 2008; Scholten and Künneke, 2016). Their framework can be applied in particular to the arrangements for critical/fundamental functions within network sectors.

The framework in this thesis focuses on flexibility management as an efficiency-improving function. This is complementary to the previous framework as it assumes already effective operation with regard to the fundamental functions in the system. The efficiency-improving functions arise as a result of IT advancements in the sector. Flexibility management, as presented here, serves cost-reduction objectives of actors through the use of IT and real-time activation, control and management of electricity flexibility. Similarly, the integration of IT could also provide a range of efficiency gains in other sectors. The design variables (**who** is responsible, for **what** efficiency gains, **how** and **when**) provide a useful structure for the organization of those new responsibilities for efficiency gains.

8.2 Recommendations for Policy Makers

8.2.1 Allow for flexibility trading by aggregators, retailers, DSOs and other new parties in existing markets

Policy makers play an important role in defining the route of energy sector developments. From a regulatory perspective, it is suggested that the entrance barriers are lowered for new actors, such as aggregators, entering existing markets with flexibility services. This could be done by reducing the minimum bidding values for traders in the different central markets (balancing, intraday, day-ahead). As shown by the cost analysis, flywheel technology and demand management are the most profitable solutions in the short term. Furthermore, as is the case in many markets with priority access for renewables, priority access for electric flexibility in markets could further support its development (Koliou et al., 2014).

As well as introducing the aspect of flexibility management in markets, it is crucial that interactions with network operators are effectively established. The potential congestions that can result from aggregated flexibility could be solved in different ways. In order to ensure coordination of the provided flexibility, it is suggested that the DSO (as an already regulated actor) would be made responsible for ensuring technical coordination of flexibility. For example, a specific aggregator could liaise between the DSO and retailer (like the aggregator model in this thesis), or the DSO could provide a separate ex ante price (time-based price) for the network capacity component, which can be internalized by the other actors in the sector (aggregator and retailer). As shown in this thesis, there are potentially many ways in which the coordination issue could be solved; examples are presented in Chapter 5. Another way to ensure technical coordination is to automatize flexibility management from specific devices for pre-set system purposes bound by network limitations through the DSO or aggregator. Such methods would limit technical and regulatory complexity and this direct control approach would result in less regulatory hassle than in a retail competition model.

In short, it is suggested that policy makers incorporate economic valuation and technical coordination in the design process of smart grids. This means that policy makers would need to create room for business model development, and prevent harmful interferences between network and supply needs for flexibility.

8.2.2 Adjusted regulation for DSO, retailers and possible coordination mechanisms

The case studies presented in this thesis reflect different possible roles for the DSO, retailer and aggregator. Many of these roles are currently not allowed because of the way in which the actors are regulated in Europe. It is recommended that, depending on the chosen techno-institutional design of flexibility management, the regulation of the DSO, retailer and/or aggregator be adjusted to allow for a transition towards well-coordinated flexibility management. An example that supports coordination between the DSO, retailer and aggregator involves *ex ante* TOU price for distribution network usage. This helps to avoid harmful interferences between network and supply, while also supporting non-discriminatory use of flexibility by other actors as retailers or aggregators can internalize these network prices in their programme scheduling.

8.2.3 Regulatory obliged flexibility

The free market and retail competition are important cornerstones in the European electricity sector. However, setting up coordination mechanisms between the DSO, aggregator and retailer would not be without difficulty in a situation where network capacity is scarce and flexibility provision is plentiful. A way to decrease complexity in the interaction between actors in a free market is to automatically enrol specific flexibility-providing units in flexibility management programmes. For example, this could be the case for EV charging stations, flywheel technologies and power-to-heat technology. In a relatively easy way, this could ensure technical coordination of flexibility for both network and supply needs. This could be done through an actor, such as the DSO or aggregator, who would be responsible for automatically activating this flexibility.

8.2.4 Smart energy networks

The 2016 European Clean Energy Package proposes development toward local energy systems (European Commission, 2016). This development of local heating and cooling networks provides significant benefits for both cost and emission reductions in the energy sector. It is suggested that such a drive towards local heating should be combined with electricity services for flexibility. It is possible that a local entity, for example an ESCO, could take over responsibility for both the heating and electricity aggregation. As described in the cost analysis, potential technologies which might be interesting from a cost perspective would be the flywheel, power-to-heat technology, micro turbine or RES curtailment from solar PV panels. However, such a local entity could also provide a platform for coordination mechanisms between the DSO, aggregator and retailer. Integrating local heating with electricity provision would further affect the space needed for new roles of actors in the energy sector.

8.3 Recommendations for Aggregators and Retailers

8.3.1 Provide new services and initiate new cooperations

As the results from the study suggest, many specific flexibility providing units could already provide interesting revenues for trading in balancing markets. It is suggested that retailers take responsibility for supporting end users to become flexibility providers. The roles of the aggregator and retailer could therefore overlap in some areas. The actor providing the best value for services to customers would win in the long term.

It is also suggested that both aggregators and retailers seek cooperation with local network operators to ensure reliable flexibility provision as well as economically viable flexibility. It is therefore suggested that retailers in particular not only focus on electricity production, but also on demand adjustment, flexibility provision in balancing markets and cooperation between potential local heating suppliers.

8.4 Recommendations for DSOs

8.4.1 Provide new services

DSOs traditionally have the responsibility for maintaining and investing in electricity networks and, in doing so, provide a level playing field for all the actors involved. Even though the retail competition model provides motivation for unbundling of services between network and supply, it is suggested for DSOs to try move beyond their regulatory responsibilities. One possibility would be for DSOs to cooperate with aggregators and retailers for effective trading of flexibility. It is suggested that DSOs should clearly define the network limitations of their grids and find ways of communicating these to other actors so that other actors can easily integrate those limitations into their scheduling.

Furthermore, it is suggested that DSOs take a clear step into the data management role that is waiting to be filled alongside the smart grid developments. As this role requires a neutral data manager, the DSO and TSO are logical candidates (CEDEC et al., 2017).

It is then suggested that DSOs keep up to date with developments in the local heating supply sectors. In the future, it could be the role of the DSOs to cooperate with such actors, or even take up additional roles as local heat suppliers. This development could be of interest, for example, in European countries with high heating requirements and high penetration of renewable electricity (e.g. Denmark, Norway, Finland and Sweden).

8.5 Future Research

8.5.1 Cost data

The quantitative analysis of the costs of the different flexibility providing units is based on data published by the US National Renewable Energy Laboratory and the United States Department of Energy. However, most of the data was taken from reports dating from 2010, 2013 and 2015 (see Annex 1). It is expected that the costs of the technologies decrease with economies of scale in production, technical innovation and increasing demand for those units and so it is likely that the cost figures will have changed since then. It is therefore suggested that future research should analyse the investment costs and STACs using more recent data. Due to technical developments and economies of scale in production, it is expected that the costs might have reduced over time.

It is also important to state that the cost assumptions for electricity and gas prices and potential revenues were based on data from the Dutch system. This therefore cannot be presented as a totally European analysis. Future research could improve the analysis by showing the day-ahead and balancing market prices for more than one TSO and including the electricity and gas costs from the local region. The bias towards the Dutch system mostly affected the cost inputs of fuel requiring DERs (RES curtailment cost, gas turbine, micro turbine, power to heat, and excluding storage devices) and affected the levels to which the costs have been compared in the central market. This therefore shows in relation to the Dutch gas/electricity cost, how large the discrepancies are with the central balancing and day-ahead market.

Further research should also include aspects that make local flexibility-providing units relatively cost comparable with large power generators in central markets. This work presented an initial step towards such cost comparison, but it is important to note that the current price setters in central markets are largely coal, gas and nuclear production units, which frequently receive government subsidies to contribute to the large upfront costs. Furthermore, these units are generally not penalized for the externalities that they cause to the environment. Due to the large stranded costs in these production units, it is inevitable that electricity power prices will be low in cases of oversupply, especially with additional inflows of renewable generation with priority access. This aspect of unpredictable inflows from clean renewable sources has not been taken account of in the existing market models or in the asset base in the sector. As soon as this traditional production units reduce their market share, and renewable inflows increase substantially, the need arises for market models that support more real-time demand adjustments, provide priority access to flexibility management (e.g. DR) and motivate both generation and production to react (close to real time) to the current system status. The author suggests that future research should take account of those aspects that make local flexibility-providing units relatively cost comparable with large power generators in central markets.

8.5.2 Demand management and device-related costs

The STACs for demand management were set at zero in the analysis due to the absence of specific costs for the reduction of demand from devices. However, in addition to the technical costs (like fuel, investments, O&M), there might also be socio-economic costs involved in the activation of flexibility, i.e. the opportunity cost. Opportunity cost is the cost that would be incurred if the flexibility was not provided and the unit served another purpose – for example, when a taxi EV is used to drive and transport a passenger instead of providing flexibility to the system. If account was taken of such opportunity cost, then the value of upward and downward flexibility could be very different and even more time dependent, making the cost values strongly context dependent. This is also the case for demand management, which in this case shows a cost of €0/kWh. This is therefore to be replaced with the specific context-dependent opportunity cost of using a device uninterrupted.

A similar issue can be seen in relation to the opportunity cost for a solar panel. When this unit is curtailed, income might be foregone, thereby creating an opportunity cost. In a situation where the context is fixed, it could be interesting to examine opportunity cost issue in order to analyse the profitability of management flexibility from a socio-economic as well as a techno-economic point of view. However, it must be noted that such values of opportunity costs are very situation dependent and could therefore reduce the ability to generalize results.

8.5.3 Information technology (IT) costs and data management organization

The costs of IT equipment and data storage remained outside the analysis of this research. To effectively develop smart grids, it is important that the responsibilities for data management are well defined and integrated with the techno-institutional design for flexibility management. To provide a complete picture of costs for flexibility management, it is recommended that future work should include the cost for data management and describes the responsibilities and privacy regulations for the data management in the sector.

8.5.4 Multi-energy systems

This work focused mainly on the issue of flexibility management for the electricity system. However, as well as electricity, heat, cooling and gas could also be included in a smart energy system design and operation. Such local energy systems are also the focus of the 2016 Clean Energy Package with district heating and cooling for improving energy efficiency and reduction of carbon emissions (European Commission, 2016). It is suggested that a local approach is chosen for heating and cooling networks. Future work could analyse the realization of multi-energy systems in a retail competition context. For example, new actors like ESCOs could be providers of energy and might offer a range of services such as heating, cooling and gas supply for a particular urban district.

8.5.5 Social aspects

This thesis has not included any analysis of the social aspects of smart grids, i.e. how end users would respond to, for example, direct control or a dynamic electricity price**. T**he control of devices without customer consent might lead to end-user disengagement with flexibility programmes and therefore counteract the actual realization of effective electric flexibility. For successful transition to innovations in the electricity sector, it is therefore crucial that future work takes account of social aspects.

It is therefore suggested, that for successful uptake of flexibility from end users, future research specifically focuses on the techno-institutional design for household appliances only. Due to the specific characteristics of end-user ownership and placement of household appliances, it is recommended that future research therefore distinguishes between two techno-institutional designs: one for household appliances and the other for DERs. In this way, future research will be able to help find the most suitable flexibility management approach for different types of flexibility-providing units and end users in the electricity sector. However, if flexibility management becomes a market product (which the author believes is the case), it is expected that the market participants (retailers and aggregators) will assume part of the responsibility to find suitable models that benefit end users and society as a whole.

8.6 Reflection

8.6.1 New regulatory approach

In Europe, the retail competition model forms the regulatory context of the electricity sector. A totally different model could be one aimed at self-regulation of local electricity systems. Self-regulation refers to systems in which local communities own and (indirectly) take decisions about the operation of the local electricity (and possibly energy) system. An example of such a system is presented in Chapter 5, in the Local Integrated Utility case study. Regions with a prevailing interest for local ownership and renewable energy generation could be flagship projects for these developments. Further possibilities would be to have local cooperatives integrated with the provision of local heating and cooling networks. This approach of self-regulation and shared ownership could be an interesting possible direction for specific cases. However, for larger cities, where local ownership might be troublesome, new methods of ownership might be needed to still allow for self-regulation without moving towards monopolistic power tendencies of the local utility.

Another issue to reconsider is that of privatization within the electricity industry. In Europe, many developments have moved towards the privatization of electricity supply services, but not that of electricity networks. An important question can be posed here. First of all, is the electricity network a public good – meaning, should everybody have a universal right to an amount of network transport capacity at each moment in time? If electricity transport at a moment in time is not providing enough capacity, is this violating the universal access principle of a public good or merely a sign of inefficient system operations? Normally, for a public good, government policy would ensure universal access. In the electricity sector, installing enough capacity is one of the quickest ways to accomplish this. However, the IT revolution actually shows the experimentation with new market models that could privatize not only the electricity retail/supply service but also slightly the network capacity allocation. With IT real-time data collection and direct control, end users who do not pay their bills can actually be “switched off from the network” theoretically. It is important to make a clear decision whether the network should stay a public good or become a private good. If it becomes a private good, further research should be done with regard how capacity allocation should be arranged, especially in times of congestion.

8.6.2 Economics of externalities versus flexibility management

Smart grids can provide economic and technical value through the management of flexibility in electricity systems. From the perspective of institutional economics, the flexibility of end users could be seen as an externality that should be properly managed, just like carbon emissions. However, it is important to note that electric flexibility does not naturally exist without proper (financial) incentives. Therefore, seeing flexibility as an externality is a misconception, leading to a wrong approach for the design of flexibility management incentives. Knowing that efficient electric flexibility does not exist without financial incentives (unlike emissions and other negative externalities which are inherently produced in the value chain), a market, incentives or regulation are preliminary requirements for the activation of useful flexibility. An important note to take away from this work is therefore that electric flexibility *becomes* available after setting effective incentives, markets and regulation and is not present in the system by default. Actors will not invest in flexibility-enabling technologies if there is no value at all for the recovery of those investments. The framework in this thesis has laid the groundwork for techno-institutional design to both enable and manage flexibility to attain efficiency gains in the sector.

9 Published Paper I: The Economic Effect of Electricity Net-metering with Solar PV: Consequences for Network Cost Recovery, Cross Subsidies and Policy Objectives

*Entire manuscript of the published paper in Energy Policy (2014), 75, 244–254 by **Eid, C.**, Reneses Guillén, J., Frías Marín, P., & Hakvoort, R.*

9.1 Introduction

Residential electricity consumers are increasingly motivated to install distributed generation (DG) units due to supportive renewable policies and decreasing costs. For instance, Europe's residential and commercial sector already had 36.6 GWp of solar photovoltaic (PV) panels installed in 2012. Likewise, large numbers of PV installations are noticed in The United States (US) within California, Arizona and Hawaii (Greentech Media & Solar Energy Industries Association, 2013). The owners of PV units are frequently rewarded for the electricity fed-back into the grid through net-metering. Net-metering is a practice by which owners of PV units may offset electricity consumed against their production during a certain period of time (European Photovoltaic Industry Association, 2013; NREL, 1996; Wan & Green, 1998). Net-metering is positively perceived for these PV-owners due to the fact that it leads to reduced cost of customers' final electricity bills and therefore incentivizes PV installation (Darghouth, Barbose, & Wiser, 2011). Indirectly this DG installation has further positive effects on carbon emission reduction targets due to the fact that many DG units operate from renewable energy sources like solar and wind (Alanne & Saari, 2006; Darby, Strömbäck, & Wilks, 2013).

However, contrary to the DG-owner and sustainable policy perspective, the issue of net-metering and PV penetration is not positively perceived by European Distribution System Operators (DSOs) and US Public Service Utilities (Cohen, 2013; The Electricity Journal, 2013). Both types of utilities are operating under economies of scale and net-metering causes those utilities to miss part of their financial incomes while remaining providers of transport and reliability services (California Public Utilities Commission, 2013; Cohen, 2013; Lipman, Edwards, & Kammen, 2002; The Electricity Journal, 2013). More specifically regarding the network related issues of net-metering, unbundled Distribution System Operators (DSOs) in Europe perceive net-metering as jeopardizing their cost recovery for their substantial stranded costs. In order to make up for this cost gap, DSOs increase network charges. As a consequence, both PV owners and non-PV owners are required to pay higher prices for network usage. The practice of increasing network tariffs results in cross subsidies for non-PV owners due to the fact that non-PV owners subsidize network costs that PV-owners avoided to pay. This issue of cost recovery and cross subsidies has also been pointed out by others (EEI, 2013; Pérez-Arriaga, Schwenen, & Glachant, 2013).

Hughes and Bell categorized net-metering methods within a taxonomy, making clear that net-metering can be applied very differently (Hughes & Bell, 2006). Furthermore, the impact of net-metering on public and network utilities' income has been studied within numerous policy reports. Those reports argue differently regarding financial impacts of DG penetration, possibly due to the influence of main stakeholders involved (California Public Utilities Commission, 2013; Cohen, 2013; NREL, 1996). Consequently, different efforts have been made to deal with the issue of net-metering focused on financial stability of network utilities and preserving equity between ratepayers. A simplistic solution to correct for those cross subsidies is to apply a corrective tariff for DG-owners. This fee is also called a "back-up fee" in Spain or, differently, a self-consumption fee due to the fact that it might incentivize self-consumption instead of net-production. This charge was proposed in July 2013 in Spain (CNE, 2013). Furthermore in Germany, Czech Republic, Denmark, Austria and numerous states in US like Arizona discussions are ongoing regarding self-consumption charging (Bundesministerium fur Wirtschaft und Energie, 2014). Applying such fee leads to controversy due the discouraging signal it poses for PV installation and sustainability objectives. Consequently, policy makers are worldwide investigating ways to handle this controversial dilemma between sustainability on one side and cost recovery of network operators and public service utilities on the other.

Even though the effect of net-metering is discussed in different policy reports, a study of the effects of net-metering on higher policy issues like cross subsidies, cost recovery and sustainability has not been conducted. An interesting issue that remains is the impact of differently applied net-metering schemes with different types of tariff designs on policy criteria like DSO cost recovery, cross subsidies, cost-causality and DG incentives. The authors of this paper aim to provide policy insight regarding the connections between these issues. This study focuses on a Spanish case of net-metering with a PV unit for a low voltage network user, whereof the effects are mostly felt by the DSO. However, due to the fact that the nature of the US related public service utility is largely related to that of the European network operator, the results of this study are interesting for both the European and US net-metering case.

The paper is organized as follows. In section 9.2 we describe main context surrounding the net-metering issue with a description regarding the DSO, net-metering practices itself and tariff designs. In section 9.3 we present the approach and assumptions for the study and section 9.4 presents the results. Following in section 9.5, the outcomes of the study are discussed and in section 9.6 conclusions and policy implications are provided.

9.2 The Net-metering Context

9.2.1 Net-metering and DSO cost structure

The DSO incurs in operational expenditures (OPEX) and capital expenditures (CAPEX) in order to supply the electricity transport service under certain quality standards. OPEX consists of operation and maintenance costs (O&M) of network installations and costs associated to commercial services. On the other hand, CAPEX consists of mainly investments in the distribution network and are merely related to capacity utilization (Frías, Gómez, & Rivier, 2007). Due to the fact that the electricity transport service can be recognized by stranded investments and high economies of scale, the DSO cost structure this is highly CAPEX related.

Traditionally, electricity customers were solely consuming electricity. Therefore in many places in Europe volumetric charging for distribution costs (charging based on energy flows per kWh) has been sufficient to provide for DSO's income to cover for both CAPEX and OPEX expenses. This charging method is applied in still the majority of European countries for electricity distribution costs (Eurelectric, 2013). A reason for this practice can be both the simplicity of such method and the desire to keep electricity as a public good affordable for small users. However, the development of prosumption (consumers that both consume and produce electricity) disregards the underlying assumption that initiated this volumetric based charging. When the network user are solely charged for those costs per kWh consumed, the issue of net-metering is jeopardizing cost recovery for especially the stranded costs (CAPEX) which are not related to kWh consumed but to kW capacity invested (California Public Utilities Commission, 2013; Cohen, 2013; Lipman et al., 2002; The Electricity Journal, 2013). Therefore, even though the decreased electricity costs that net-metering results for prosumers and the opportunities for CO2 reduction, net-metering is not positively perceived by European DSO's and US Public Service Utilities. This is especially expected when larger numbers of prosumers are connected to the grid resulting in significant effects on the aggregated utilities' income (Cohen, 2013; The Electricity Journal, 2013).

Beside this, another potential problem arises due to net-metering combined with volumetric network charging. In order to make up for the cost gap to cover the CAPEX expenses with the energy based charges, DSOs increase volumetric network charges. As a consequence, both PV owners and non-PV owners are required to pay higher prices for network usage. Therefore the second problem is inequality issues that arise after such tariff adjustment due to the fact that non-PV owners subsidize network costs that PV-owners avoided to pay. The issues of cost recovery and cross subsidies have been also pointed out by others (EEI, 2013; Pérez-Arriaga et al., 2013).

If the problem of cost recovery and cross subsidy is not significant, especially in places with small numbers of prosumers, it might be considerable to disregard this issue due to its limited impact. However, in places with high potentials of PV penetration, for example in California, Spain, Italy and other places, reconsideration is worth the effort due to the significant challenges that it poses in the long term. Both in the European case with unbundled DSOs and the US case with more integrated service utilities, the tariff design contains ex-ante considerations of network utilization and income distribution.

9.3 Net-metering and Policy Objectives

In this paper net-metering is considered as a method by which prosumers can receive compensation for their electricity production through their reduced electricity consumption bills. Besides net-metering, which is more indirect incentivizing DG, there are other ways by which the prosumer more directly can be compensated for electricity production. With a feed-in tariff (FIT), prosumers can sell all the electricity produced by the PV unit, but have to pay the consumption price for all electricity consumed. The FIT is applied in for example Germany, where prosumers with PV panels installed from 1st of April 2014 smaller than 10 kWp, receive a FIT of 13.28 ct/kWh (Bundesnetzagentur, 2014). Differently, for net purchase and sales systems, the utility only buys the net-production of the household. Thus, surplus PV-generated electricity, which is the PV-generated electricity actually fed into the grid at times when PV generation exceeds electricity consumption, is purchased at a set price. Net purchase and sales is adopted in Japan (Yamamoto, 2012).

Net-metering by itself can be applied in numerous ways (Hughes & Bell, 2006) and therefore, even though named similarly in places, might differently affect policy objectives. Net-metering requires a bi-directional meter which monitors both consumption and production of the PV-owning household. The prosumer could install the (bi-directional)meter in distinct locations and due to that, net-consumption, net-production and/or total PV production could be metered. The locationing of the meter(s) defines what is metered, see Figure 9.1 for some possibilities as inspired by the Italian regulation for net-metering (Comitato Elettrotecnico Italiano, 2012).

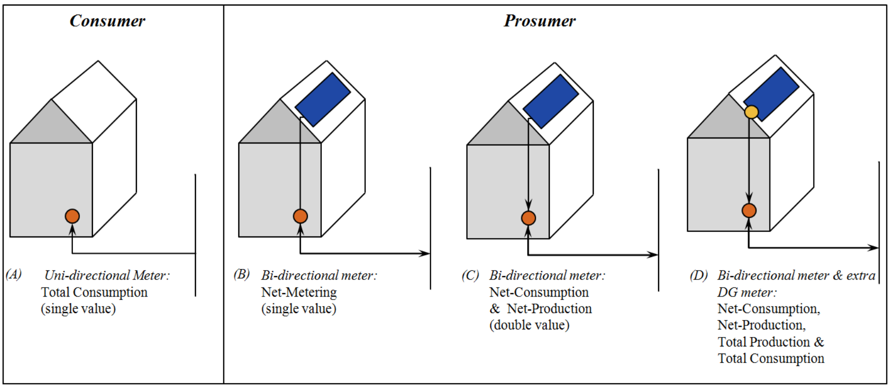

Figure 9.1: Visual presentation of some possible metering options

A policy based classification is presented in Figure 9.2 which categorizes net-metering by technical and accounting aspects and possible influences on criteria that are important to energy policy makers. From the technical aspect, net-metering is defined by the physical meter that is an either uni-directional or bi-directional. Uni-directional metering represents electricity metering that solely registers electricity consumption from the grid. Uni-directional metering therefore does not monitor surplus electricity production that is fed back into the grid. This type of metering is classically applied in residential households since traditional electricity consumers were solely seen as consumers, not producers.

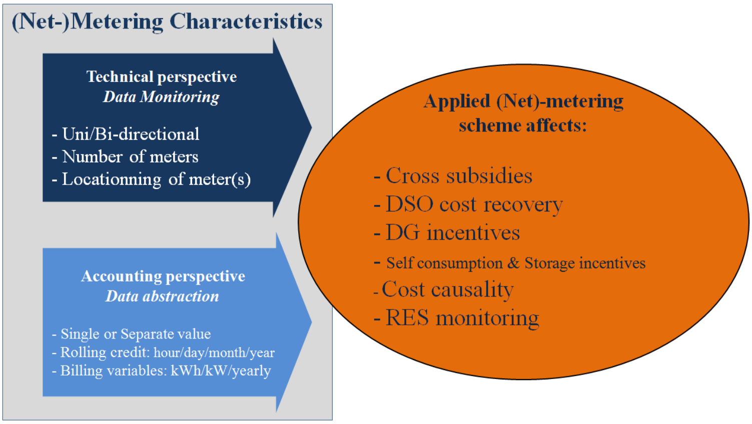

Figure 9.2: Net-metering and its influence on energy policy criteria

Bi-directional metering represents electricity metering in two directions, both for consumption and production. Most of the times, uni-directional electricity meters are replaced by a bi-directional meter when a PV unit is installed, in order to monitor the amount of electricity fed-back into the grid and/or to support the registration of the total amount of RES production in a nation. Sometimes even a separate meter is placed directly at the production unit (see Figure 9.1 option D) in order to measure the exact value of such production instead of a netted value. In Europe, the 2020 objectives for sustainability require this meter configuration in order to quantify the amount of RES that is produced and to check whether the long-term objectives (e.g. 20% RES) are being fulfilled. Furthermore this type of metering is required for a system with FIT due to the fact that total PV production is rewarded and not solely net production. However, from the perspective of network user billing, the net-production and net-consumption are more of importance due to the fact those values reflect grid utilization.

Secondly, from the accounting perspective, there are different ways in which data from bi-directional metering can be abstracted and billed. This could be either separately for electricity feed-in and consumption, or a single netted value for both consumption and production together. The Italian case shows that until July 2013 separate metering was necessary for production and consumption metering, in order to properly pay out the set Feed-in-Tariff (FIT) for PV electricity production. However, this feed-in tariff has been discontinued in July 2013 due to the reach of the threshold value for annual incentives (l'Autorità per l'Energia Elettrica e il & Gas, 2013). Consequently, after July 2013, prosumers are rewarded solely by net-metering.

Furthermore, important to the net-metering case is the applied timeframe for rolling credit. The rolling credit timeframe refers to the period for which surplus of electricity production (also named net-production) at one moment in time can be used as a credit to cover for electricity consumption in other moment of time (Hughes & Bell, 2006). The period over which this crediting is possible is called the rolling credit timeframes and can be e.g. hourly, daily, monthly or yearly based. Large rolling credit timeframes of one year are applied in California (NREL, 1996). With a yearly based rolling credit the surplus production within one month remains available as a credit for the other months within one year. This results in very low electricity bills for prosumers which own large PV units. For example, Californian schools with large PV units and yearly net-metering this net-production is transferred (or rolled) as a credit for the next months within the year when the schools are open. This practice, together with energy based charging (charging per kWh), leads to nearly zero electricity bills for the schools and significantly impacts incomes for network utilities (California Public Utilities Commission, 2011).

9.4 Sequential (Net-)metering Processes: Metering, Accounting and Billing

Before a customer is charged for network utilization, three sequential processes occur: metering, accounting and billing (see Figure 9.3). Depending on the type of meter that is installed and its location, certain consumption and/or production behavior can be metered. Secondly, depending on whether there is a consumption and/or production tariff applied, production and/or consumption behavior will be accounted for or not. Lastly, the final cost for which the customer will be billed depends on the applied cost drivers and network tariff design. This tariff design could be either related to capacity, energy or unrelated to those aspects in a fixed charge. The different alternatives presented in this study relate to the below presented steps.

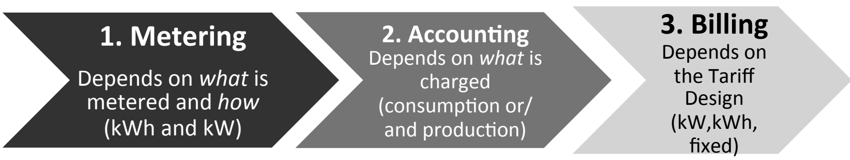

Figure 9.3: Customer network charging in different sequential steps: metering, accounting and billing

9.5 Tariff Design and Net-metering

This section presents the main billing variables that are used in network tariff design which have their specific on cost-causality and tariff principles. Tariff design provides different options for billing the network user. Firstly, billing based on transported energy (in €/kWh). In contrast to electricity supply costs, network transportation costs are mostly capacity related. Therefore this type of billing for network costs is not the most cost reflective of network utilization, but could provide signals for overall energy efficiency (Eurelectric, 2013).

Secondly, billing based on contracted capacity of utilized maximum capacity (in €/kW). The capacity charge (in €/kW) depends on the observed or the contracted maximum capacity (kW). Frequently, low voltage users are being billed by the contracted capacity, and not through an observed maximum capacity. However, the use of smart metering enables accurate maximum capacity charging of network users. With the eye on this development, such charging is taken into account in this study.

Lastly, billing based on a fixed charge (in €/year or €/month). According to Rodriguez et al, these costs can be related to the contribution to losses, the contribution to the network peak and the connection costs (Rodríguez Ortega et al., 2008). type of charge is equal for all network users within a consumer category, unrelated to their individual electricity consumption, production or capacity utilization. Even though this is a simple and clear method from the regulatory view, it however does not provide any signals to reduce capacity utilization or electricity consumption and does neither reflect cost causality.

9.6 Method

The focus of this study is to provide insight on a policy level in the cost recovery and cross subsidy issues related to net-metering and tariff design. For this purpose, the network user considered here is a prosumer owning a PV unit, based in Madrid (Spain). Even though PV generation and customer load curves are in the short term subject to many random issues, there has been no modeling needed but rather a quantitative illustration of hourly based electricity consumption and production values for this Spanish household. Differently said, consumption and production have been hourly subtracted in order to arrive to a "netted" value for the different net-metering scenarios.

For calculating the values for yearly measured kWh of the net-metering alternatives, average hourly consumption values of Spanish households were used. According to the Spanish transmission system operator (Red Eléctrica de España, 2013) the average consumption of a low voltage network user is 2508 kWh per year. The total production of the PV panel is 2570 kWh according to the used PV calculator (NREL, 2006). Real hourly consumption values are used for the results in section 9.8 regarding capacity charging.

For calculating the costs per alternative, prices are related to the access tariff for a Spanish household, which are € 38.04 for capacity (kW) and € 0.044 for energy (kWh). Furthermore for electricity feed-in (also called net-production) we use the Spanish value of €0.50 per MWh, which is € 0.005 per kWh (Ministerio de Industria Tourismo y Commercio, 2011). Even though this production charge is very low for being cost reflective, in this study we assume cost reflectivity and sufficiency.

9.7 Analyzed (Net-)metering Alternatives

Table 9.1 presents the analyzed alternatives with the combinations of physical metering and accounting possibilities as were presented in Figure 9.3. Herein, the first number presents the physical metering option applied and the subsequent number after the "M" indicates whether there is solely consumption charging (option 1) or both consumption and production charging applied (option 2). In Figure 9.4, an additional letter shows which type of rolling credit is used (“h” for hourly, “d” for daily, “m” for monthly “hy” for half-yearly, “s” for seasonal and “y” for yearly).

Accounting → / **Physical Metering ↓**	1. Solely Consumption Charge	2. Separate Consumption and Production charge
1M: Uni-directional metering of consumption	Uni-directional metering with consumption charge **(1M1)**	Not Possible, *Not Analyzed* **(1M2)**
2M: Separate metering of consumption and production	Separate metering with consumption charging (similar to 1M1) **(2M1)**	Separate metering with separate charging, (**2M2**) *No-Net-Metering*
3M: Separate metering of consumption and production with rolling credit	Separate metering with **rolling credit** and consumption charge **(3M1)**	Separate metering with rolling credit and separate charging for net-production(**3M2**) *Not Analyzed*

Table 9.1: Analyzed alternatives

In Table 9.1, it is visible that the combinations 1M2 and 3M2 are not analyzed. This is the case due to the physical impossibility of the alternative (option 1M2) and due to the fact that the option already presents a second best solution for the net-metering case (option 3M2), which is not the aim of this study. This study’s aim is to provide insights in the dynamics that are caused by net-metering through differently applied rolling credit timeframes and tariff designs.

The basic metering alternative 1M1, is uni-directional metering with a consumption charge. This type of metering and accounting does not involve production metering and a production charge and is appropriate in an electricity system with central production and consumption at the low voltage levels. The second option, 2M1, involves separate metering of consumption and production, however with only a consumption charge. This option is similar to the previous option 1M1, but presents accounting of the consumption and not of the production. Therefore the outcomes of this option are exactly the same to option 1M1 and consequently option 2M1 is not separately presented in this paper.

Thirdly, option 2M2 presents metering and accounting separately for both consumption and production. Due to the fact that electricity that is fed-back into the grid is monitored separately and not subtracted from consumption, this option is called the no-net-metering alternative. Fourthly, option 3M1 presents separate metering with a rolling credit. This means that the surplus production over consumption can be used within one timeframe. This timeframe is analyzed on an hourly, daily, monthly, half-yearly, seasonal and yearly basis. The difference between half-yearly and seasonal alternative, is that the seasonal alternative divides the year in a summer and winter period (Oct-Mar and Apr-Sept) while the half yearly method uses a division in the middle of the year (Jan-Jun and Jul-Dec). For an overview of the different alternatives, see Figure 9.4.

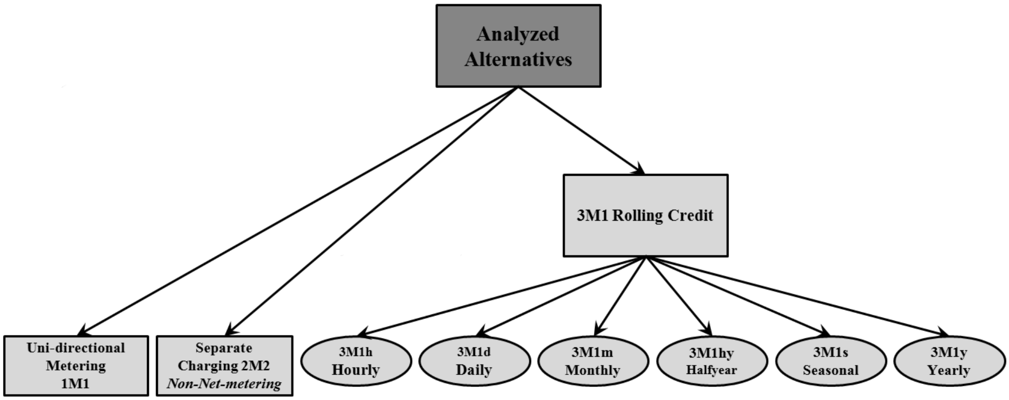

Figure 9.4: Analyzed alternatives

The different alternatives are not analyzed for the capacity charging scenarios due to the fact that the maximum observed capacity (kWmax) is not an accumulated value but rather hourly changing for both net-consumption and net-production. For the capacity charge the discussed alternatives are therefore related to the option of having a single charge for only observed net-consumption, or both observed net-consumption and net-production.

9.8 Results

9.8.1 Network billing per alternative

Table 9.2 presents the measured kWh and customer costs for each of the alternatives. In this table, self-consumption refers to the households' direct consumption of the electricity produced by the PV unit. Net-consumption presents the households' total consumption from the grid, while net-production represents the surplus electricity that is fed-in the grid. Due to the fact that the used values of consumption and production data were hourly based, there is no difference visible between the measured consumption for unidirectional an hourly rolling credit. However, in real life, with smaller measuring intervals, the hourly kWh values could be slightly lower than of the unidirectional billing alternative.

	kWh measured per year	Euro per year		kWh measured per year	Euro per year
Uni-directional metering (1M1&2M1)			***Monthly*** **rolling credit (3M1m)**		
Consumption	1528	61.12	Net-Consumption	352	14.08
			Net-Production	413	
Separate metering (No-net-metering) (2M2)			***Seasonal rolling credit(3M1s)***		
Net-Consumption	1528	61.12	Net-Consumption	311	12.44
Self-Consumption	980				
Grid feed in production	1589	0.7945	Net-Production	372	
Total Production	2570				
Hourly **rolling credit (3M1h)**			***Half yearly rolling credit (3M1hy)***		
Net-Consumption	1528	61.12	Net-Consumption	14	0.56
Net-production	1589		Net-Production	76	
Daily **rolling credit (3M1d)**			***Yearly*** **rolling credit (3M1y)**		
Net-Consumption	471	18.84	Net-Consumption	0	0
Net-Production	532		Net-Production	62	

Table 9.2: Billed yearly network costs with an energy tariff

The billed consumption largely depends on the tariff design that is applied. The following sections present the outcomes if an energy tariff (section 9.9), capacity tariff (section 9.10) or fixed tariff (section 9.11) would be applied.

9.9 Energy Tariff

If an energy network tariff is applied, this means that a volumetric charge per kWh is billed for the network usage. Even though the network cost are mostly capacity based, the energy charge could, among others, be aligned with the contribution to electricity losses that are caused by the network user (Pérez-Arriaga et al., 2013; Rodríguez Ortega et al., 2008).

Table 9.2 presents the outcomes regarding billed network costs for each of the net-metering methods with an energy network charge of €0.044. Due to the fact that traditional metering solely charges consumption, only consumption values are provided for the options. However, only for the option of separate metering we calculated also a production charge. In theory, the production charge could be lower or higher than the consumption charge and could even be a benefit due to the fact that electricity feed-in might decrease network losses by satisfying local electricity demand. According to Li and Tolley, DG production should be charged if this generation rises above local network consumption, (Li & Tolley, 2007). However, for this study we are mainly interested in the effects of potential decreased DSO incomes and cross subsidies due to net-metering. Therefore the dynamics related to DG penetration are not of interest here and we assumed that DG penetration will not decrease or increase network cost but those costs remain the same for the DSO.

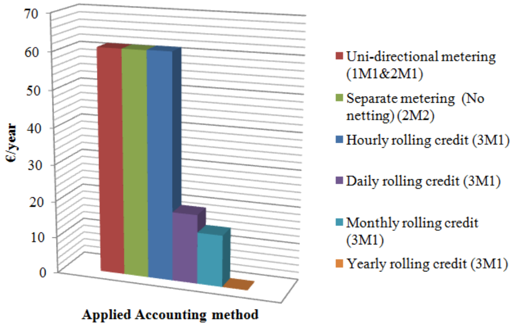

Figure 9.5: Billed yearly network costs with an energy tariff for different types of net-metering

The no-net-metering option displays consumption that is fully charged and not decreased due to net-production. The alternatives with a rolling credit present decreased billed network costs, which is also visible in Figure 9.5. For the DSO this demonstrates a decrease of incomes if volumetric charging would be applied, with 69% income decrease for daily rolling credit, 77% for monthly rolling credit, 80% for seasonal rolling credit and 99% income decrease for the application of a monthly rolling credit. Regulation allows for adjustment of energy charges per kWh and thus creates potential for cross subsidies between PV owners and non-PV owners.

As seen in Figure 9.6 and 9.7, with an hourly rolling credit, the production and consumption levels are different depending on the day of the year. Figure 9.8 shows the development of this monthly rolling credit on a yearly time span, showing that in summer periods billed consumption is zero in most cases.

In order to show the impact on potential cross subsidies, Table 9.3 shows the potential cross subsidies in percentages for a PV penetration of 20% for each of the different net-metering alternatives with energy charging. The values are calculated assuming cost recovery for the DSO would take place if the set energy charges would be paid by each network user without any netting practices. To calculate the values, the amount of missed income due to the net-metering alternative has been divided by the total DSO incomes (€10,032 per year for each 100 customers) for the same case without net-metering. For the option of yearly rolling credit (3M1y) PV owners do not pay any energy charge and therefore this option would result in 20% of the end-users not paying anything for the network usage. If the DSO would increase energy charges for all network users to make up for this income gap, this results in the presented potential share of cross subsidies.

Hourly rolling credit (3M1)		Seasonal rolling credit *(3M1s)*	
Missed kWh (kWh/year)	784	Missed income (€/year)	1,757.6
Potential Cross subsidy	7.8 %	Potential Cross subsidy	17.5 %
Daily rolling credit (3M1)		**Half-yearly rolling credit *(3M1hy)***	
Missed kWh (kWh/year)	1,629.6	Missed income (€/year)	1,995.2
Potential Cross subsidy	16.2 %	Potential Cross subsidy	19.9 %
Monthly rolling credit (3M1)		**Yearly rolling credit (3M1)**	
Missed kWh (kWh/year)	1,724.8	Missed income (€/year)	2,006.4
Potential Cross subsidy	17.2 %	Potential Cross subsidy	20%

Table 9.3: Potential percentage of cross subsidy between network users with energy network charging for 100 users

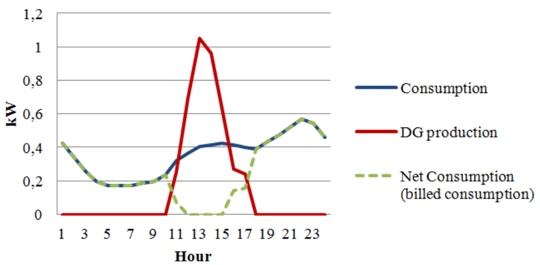

Figure 9.6: Electricity consumption and production on 1st of January

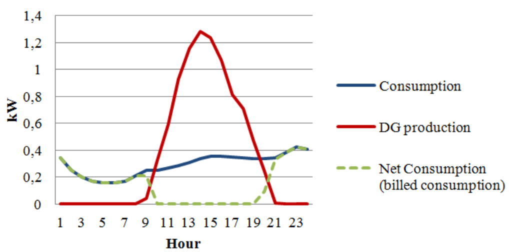

Figure 9.7: Electricity consumption and production on 1st of July (3M1h)

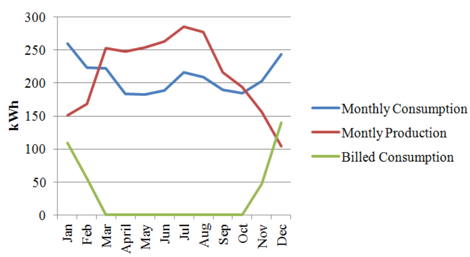

Figure 9.8: Monthly rolling credit for a year

9.10 Capacity Network Tariff

Besides the energy charge, the network tariffs could be set up by a capacity charge for either or both (net-) consumption and (net-)production. Generally the low voltage network users pay a contracted capacity charge for consumption and/or production. However, a charge of observed maximum consumption and/or observed maximum production capacity (kWmax) is used here for improved cost causality. From the perspective of cost allocation, this capacity charge could be defined by the network users' contribution to network peak to allow for an even more cost reflective signal. Defining the charge level is a technical and network dependent issue, which is not in the objective of this study.

As can be seen in Figure 9.5, Spanish peak consumption normally takes place around 11 PM, while at 1 PM the peak solar PV production occurs. Consequently, maximum observed consumption capacity values for each of the alternatives are exactly equal with and without a PV unit (value of 0.62 kW). The reason for this equality is the fact that peak electricity consumption and PV production do not occur simultaneous in Spain. For the average consumption capacity value, the variability found between observed maximum net consumption levels range between 0.40 kW and 0.61 kW throughout a single year. However, real values for households located in Madrid present different load curves than the average one (see Figure 9.9 for real values).

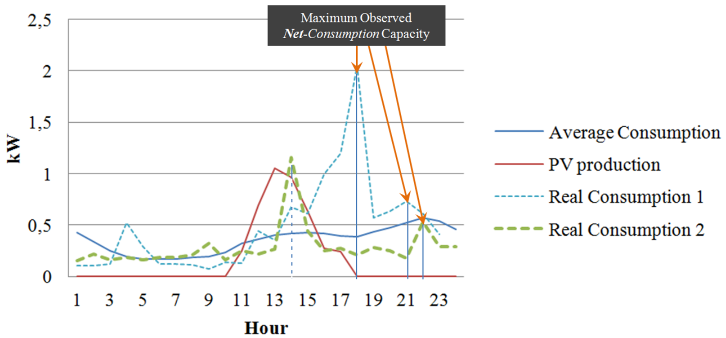

Figure 9.9: Daily basis observed consumption and production on 1st of January

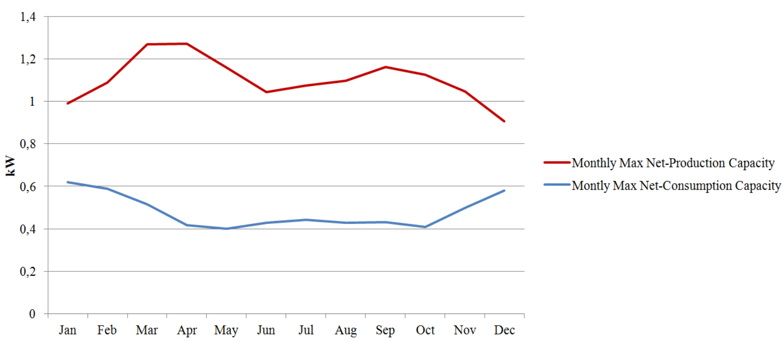

Figure 9.10: Observed max capacity over a year with average consumption

For real consumption 1, the maximum observed capacity is found to be at 18.00 with a capacity of 2,05 kW where there is no simultaneous PV production found. For real consumption 2 at 14.00 a maximum household consumption occurs with the value of 1.159 kWh; however at that moment also a production of 0.96 kW occurs, resulting in a net-consumption of 0.20 kWh. Therefore the maximum observed net-consumption is found to occur at 22.00 with 0.53 kW, where there is no simultaneous production observed. Therefore, the level of net-production depends both on solar irradiation levels and the households' self-consumption levels at production moments. As visible in Figure 9.10, low observed net-production capacity are found in the month December (0.91 kW) and the highest value is found in the months of April and March (1.27 kW).

9.11 Network Charging and the Effects of Storage

The use of a storage unit significantly affects net-consumption and net-production levels of a household. In order to illustrate this, Table 9.4 provides the measured energy and capacity for three options. The analyzed Madrid based household has in each of the options an equal daily consumption level and consumption profile and a total consumption of 6.30 kWh. For both the second and third option a 2 kW sized PV panel is taken into account and the 3rd option considers a 2 kWh battery storage. For calculating the respective values, we assumed that the storage unit is charged directly when surplus PV production would take place and is un-charged directly after if normally grid consumption would take place. No further optimization has been applied due to the fact that energy and capacity charge levels used here are not time dependent.

	Option 1 Non-PV owner	Option 2 PV-Owner	Option 3 PV-Owner with Storage
Total Energy Consumption (kWh)	6.30	3.70	1.70
Net-Production (kWh) (feed-in)	0.00	2.37	1.33
Maximum Observed *Net-Consumption* Capacity (kW_{max})	0.43	0.43	0.27
Maximum Observed *Net-Production* Capacity (kW_{max})	0.00	0.74	0.55
Fixed Charging	Independent of network utilization		

Table 9.4: Daily values for energy and net-capacity on 1st of July

For option 1, the non-PV owner is logically measured the highest consumption for both energy and capacity. The addition of a PV-unit lowers the net-consumption of the household from the grid with 41%; however, it does not affect the maximum observed consumption capacity from the grid due to the fact that peak consumption does not coincide with PV production. Option 2 presents the highest network impact due to electricity back-feeding into the grid, with 0.74 observed maximum net-production capacity. It is visible in table 9.4 that option 2 causes higher impact on the grid than option 1, due to the issue of electricity back-feeding.

In a situation with energy charging and short rolling credit timeframes (for example hourly) a storage unit would provide extra flexibility to significantly reduce the prosumers' electricity bill. However, with increasing rolling credit time frames (for example half yearly or yearly), the storage incentive would lose its influence due to the fact that, without extra cost, the network already provides the storage possibility (intrinsically within the size of the rolling credit timeframe).

More specifically regarding capacity charging, in Figure 9.11 it is visible how storage could affect the maximum observed net-consumption capacity. Figure 9.12 shows how storage decreases net-production capacity more significantly than the net-consumption capacity.

Consequently, applying solely consumption based capacity charge would incentivize network users to decrease this maximum observed capacity with local storage. This incentive would be even stronger if also a production capacity charge would be applied. This incentive could positively affect sustainability and security of supply targets.

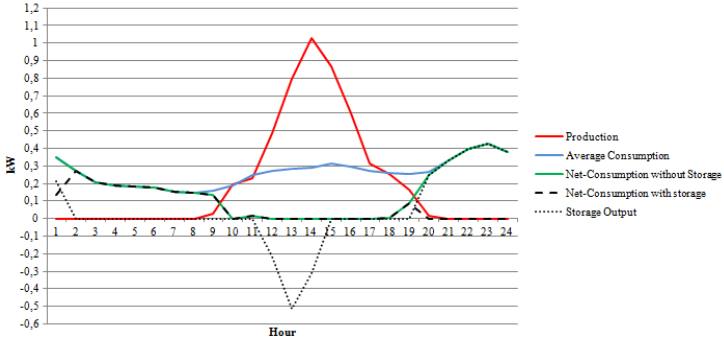

Figure 9.11: Hourly metering with storage (net-consumption)

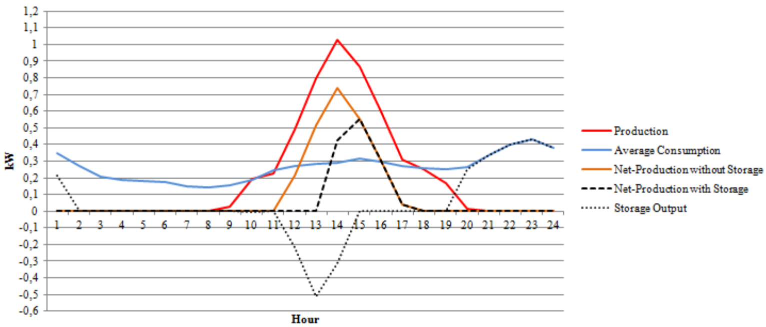

Figure 9.12: Hourly metering with PV storage (net-production)

From a regulators' perspective, self-consumption and storage should be encouraged above the PV only alternative because this decreases risks for the network. Even though this incentive for local storage will reduce DSO incomes, this does not affect cross subsidies due to the fact that actual grid utilization of the user is reduced. A PV unit without storage would transfer this "storage risk" to the network, resulting in surplus PV production that is directly fed-back in the grid with a high maximum observed production capacity of 0.74 kW. This causes that the non-PV owner might in fact reduce net consumption from the grid but utilizes the grid more intensively for net-production. With only an energy consumption charge this behavior would not be incentivized and therefore a production and consumption capacity charge or production energy charge would improve cost-reflectivity.

9.12 Fixed Network Tariff

When an electricity network user is billed with a fixed network tariff, the final bill does not depend on the amount of electricity consumed or produced. This type of tariff driver for network users does not affect DSO income, but results in cross subsidies between network users (Castro & Dutra, 2013). Furthermore, from the regulatory perspective, this type of network charging does neither reflect any cost reflectiveness of the network users' nor incentives for efficient network utilization, except for commercial distribution costs (Reneses & Rodríguez Ortega, 2014). Therefore, even though fixed tariffs are simple and effective for DSO cost recovery, they are not suggested for incentivizing the long term efficient use of the network.

9.13 Discussion

The results of this study show that net-metering combined with an energy tariff (or volumetric tariff) causes major decrease of DSO incomes and a potential for cross subsidies (see section 9.9). This effect is being amplified with larger rolling credit timeframes. For example, with a rolling credit timeframe of a year, the network user was not billed any network costs at all. Applying such energy network tariff potentially leads to cross subsidies between network users due to the fact that the DSO is upward adjusting such charges. For the network user the reduced electricity bill would be perceived as a financial incentive for PV installation and operation.

On the other hand, regarding capacity charging, the impacts on DSO income levels firstly dependent on whether solely consumption or both consumption and production capacity charging is applied. This impact depends on whether practically the households' consumption and PV production coincide or not. In Spain, at 10.00 PM the consumption peak occurs, when there is no PV production resulting in a maximum observed consumption capacity for households that remain the same if compared to a non-PV alternative. However, maximum observed production capacity changes in time due to changing solar irradiation levels within a year and the amount of coincident consumption that occurs at midday. Even though decreased capacity due to PV penetration might be the case in some countries which will be affecting DSO income levels, this does not affect arising cross subsidies between network users if also a production capacity charge is applied. Differently, a fixed charge provides equal pricing between all users and consequently this option is not preferred if behavior adjustment of network users is desired.

Net-metering demands a twofold distinction on main economic effects; the side of DSO cost recovery and the side of cross-subsidies between network users. Certain net-metering and tariff procedures might affect DSO cost recovery, while not affecting cross subsidies (for example with observed capacity charging). Contrastingly, the practice of energy charging and "netting" both impacts cost recovery of the DSO and affects cross-subsidies between network users. Figure 9.13 provides an overview of the relationships between network tariff design combined with the practice of net-metering and possible policy objectives. The arrows present a relationship and the plus (+) and minus (-) signs show whether this relationship has a positive or negative effect compared to the situation without this particular case.

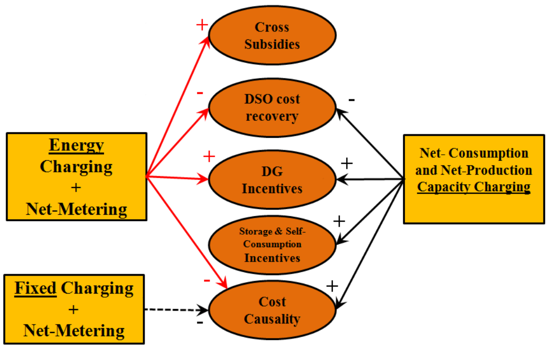

Figure 9.13: Relationships between net-metering, tariffs and policy criteria

With short rolling credit timeframes the period over which electricity production could cover for consumption is very small and therefore a storage unit would provide extra flexibility. This consequently reduces net-consumption and net-production. With increasing rolling credit time frames, there would be no significant effect on net-production due to the fact that the network provides this storage function.

Due to location and study dependent variables in this study, the next issues should be considered when passing the results and conclusions of this study to other cases.

9.14 Patterns due to Consumption, Production and DG ownership

In this study the average load curve of a low voltage network user has been used as published by the Spanish system operator. Other outcomes are expected if load patterns differ, for example, for French households with electric heating the load curves could be significantly different. This would imply that the rolling credits could impact the billed consumption and production differently than presented here.

Besides load pattern dependencies the outcomes are dependent on the type, size and location of the DG installed. For example, dispatchable units like heat pumps or non-dispatchable units like small wind power units provide very different production patters compared to PV. Consequently, due to the fact that different DG units have different coincidental production probabilities with consumption, this could lead to differently measured energy and capacity values and thus altered impacts on cross subsidies and incomes for the DSO.

Most households in Spain do not own a PV unit and therefore the general load consumption curves for a low voltage user in the used scenario would suggest that the consumption values for PV owners would be similar to those for non-PV owners. However, in reality there seems to be a relationship between PV-ownership, energy efficiency and self-consumption incentives (European Photovoltaic Industry Association, 2013). Therefore the consumption patterns of those users are expected to be lower than presented.

9.15 Costs versus Benefits for the Network with PV

In this study we assumed that costs for the network are not affected by the penetration level of PV but network costs remain equal for both consumers and prosumers. Some authors claim that in the initial phase of PV penetration the costs for the DSO would decrease (due to losses reduction and supply of local electricity demand). However, in the long term with additional integration of PV local production could surpasses local demand and therefore would cause extra costs for the DSO (Li & Tolley, 2007). Differently, in the US the Clean Power Research report for Austin Energy favored a holistic approach for PV-owner charging that takes into account avoided fuel costs, avoided capital and environmental costs (Clean Power Research, 2006). These issues are not taken into account in this paper due to the fact that the study focused on the dynamics that are resulting from "netting" of distribution charges from an unbundled distribution network operators' perspective.

9.16 Other Issues: Metering and Spanish Network Costs

Due to the fact that the most accurate value of consumption and production data was hourly based, there was no difference presented between the measured kWh for uni-directional and hourly metering. In reality however, with smaller measuring intervals (generally 15 minutes), the final measured kWh for hourly metering could be slightly lower (due to a possible crediting of production over consumption within an hour) than of the uni-directional billing alternative.

We assumed in this study that the interchange moment between different timeframes always happens at 00:00 in the night. Different outcomes are expected if the interchange moment would be set on a different moment of the day. Furthermore, in this study we focused on the individual impacts of cost drivers, while the effects of different combination of tariff drivers would result in different types of impacts. Lastly, current network costs for the Spanish households were used here for consumption and for production charging. We assumed that those values were sufficient to ensure cost recovery for the Spanish network operators. However, in other places where other network related costs for both net-consumption and net-production are present, these final costs for network users would be different and this would cause different outcomes.

9.17 Conclusions and Policy Implications

Net-metering presents an important dilemma between incentivizing distributed generation (DG) on one side and securing financial stability of the Distribution System Operator (DSO) on the other. This issue is increasingly complex due to the fact that net-metering itself can be applied differently with regard to processes of metering, accounting and billing of the network user. This paper has presented a study to provide insight into the dynamics that result from different types of net-metering methods and the impact on DSO incomes, policy objectives and arising cross subsidies between network users. This study has been carried out using hourly consumption and production data for a low voltage network user in Spain with a Madrid based photovoltaic (PV) panel of 2 kWp capacity.

Mainly, this study shows that net-metering with increasing rolling time-frames combined with an energy network tariff (also called volumetric charge) decreases DSO incomes and impacts cross subsidies. Generally, the longer the chosen rolling credit time frame, the more electricity consumption is netted by PV production. Net-metering with a daily based rolling credit and energy charging would decrease DSO income per household by 69% compared with the non-net-metering alternative and by 77% if monthly time periods would be applied. More drastically, a yearly based rolling credit would result in zero network incomes for the DSO. Due to the fact the DSO's are allowed to correct their charges upward for their missed incomes, this issue presents a large potential for the development of cross subsidies between network users. As the results show, if total PV penetration would be 20% of the end-users, the potential for cross subsidies reaches 7.8%, with daily rolling credit, 16.2 % with half-yearly rolling credit and 19.9% with a monthly rolling credit.

Furthermore, this research presented impacts due to the application of capacity charging. Firstly, observed maximum capacity charging improves cost-causality compared to charging by contracted capacity. From the perspective of cost allocation, if such charge would be calculated by the network users' contribution to the network peak, this would even present more cost reflectivity. In Spain, the electricity production of a PV panel does not affect the level of maximum observed consumption capacity due to the fact that daily peak consumption occurs at night times (10.00 PM) and does not coincide with maximum consumption. However, the study showed that the PV-owner would utilize the network more than the non-PV owner due significant surplus production that is fed back into the grid. Applying a consumption based maximum observed capacity charge would incentivize network users to decrease this observed capacity, for example trough local storage and increased self-consumption. Furthermore, in a situation with energy charging and short rolling credit timeframes (for example hourly) a storage unit would provide extra flexibility to significantly reduce the prosumers' electricity bill. However, with increasing rolling credit time frames (for example half yearly or yearly), the storage incentive would lose its influence due to the fact that, without extra cost, the network already provides the storage possibility (intrinsically within the period of the rolling credit timeframe).

Even though this incentive for local storage will reduce DSO incomes, cross subsidies are not affected due to the fact that actual grid utilization of the user is reduced. In short, applying observed capacity charging could increase cost-causality and incentivize local storage and self-consumption which consequently positively impacts security of supply and sustainability objectives.

Besides the energy charge and capacity charge, a fixed charge is in Europe generally applied for network users. The amount of income for the DSO will not be affected by net-metering practices if fixed charging is applied. Even though this option can be simply applied without any metering efforts, it is not recommended due to the absence of cost reflectivity and (storage) incentives and is therefore not suggested as a standalone charge for the network utilization.

Currently, in most European countries an energy charge is applied for network users. The authors recommend that, in the light of the obtained results, the practice of volumetric charging combined with net-metering should be reviewed. Net-metering, which was meant to encourage PV penetration seems to lead to financial instability of the DSO and furthermore is the source for potential cross subsidies between network users. In order to continue supporting PV without financial instability of the DSO, the authors recommend that explicit incentives options for PV should be provided instead of the current implicit incentives which are evolving due to net-metering.

Firstly, this would involve eliminating the practice of "netting" of network related costs due to net-metering. This could be handled by applying bi-directional metering with both consumption and production charging. Furthermore this involves improving cost-causality and creating storage and self-consumption incentives with billing based on observed capacity. Such type of metering and billing demands consensus concerning the applied metering method (bi-directional with single net consumption value or separate consumption/production value), the location of the meters and the applied type of capacity metering. For example, maximum observed capacity metered from the total production, total consumption or the netted consumption and production.

Secondly, in order to continue financial support for PV, other options for PV remuneration should be applied. Such options could include direct subsidies like feed-in tariffs in order to replace net-metering practices with or without net purchases and furthermore feed-in premiums or tax reductions.

Further research should attempt to define the appropriate level of proposed capacity and energy consumption and production charges. Defining the level of this charge demands a study in itself and is technical and network dependent. The research could provide insight in possible combinations of energy, capacity and fixed charges within tariff design and their effects on cost-reflectiveness and cost recovery of the DSO.

Finally, important to note is that the applied tariff design for network related issues is many times too much dependent on energy flows, while the actual costs are rather capacity based. The absence of cost reflectivity (for example with the fixed tariff and energy tariff) is caused by the already embedded tariff design and is merely being intensified with the net-metering practice. Main issues regarding arising cross subsidies and cost causality are thus not caused by net-metering, but by the initial embedded tariff design for the network service. Even though energy network charging is not entirely cost reflective, this still applied in many European Member States still. This therefore first requires revision towards more cost reflectivity before analyzing the net-metering practices at stake.

10 Published Paper II: Managing Electric Flexibility from Distributed Energy Resources: A Review of Incentives for Market Design

This is the manuscript of the paper published in Renewable and Sustainable Energy Reviews (2016), 64, 237-247 by ***Eid, C.****, Codani, P., Perez, Y., Reneses, J., Hakvoort, R.*

10.1 Introduction

Traditionally low voltage grids have been designed to transport electricity towards residential users for consumption. However, due to the increased penetration of distributed energy resources (DER), low voltage grids are increasingly used as carriers of bi-directional electricity flows. The penetration of DER such as distributed generation (DG), electric storage and electric vehicles (EVs) significantly affect the operations of distribution grids (Pérez-Arriaga and Bharatkumar, 2014; Pudjianto et al., 2007). In Germany for example, the growth of Solar Photovoltaics (PV) reached a level of 38 GW installed in 2013 and affected grid stability in some local areas (von Appen et al., 2013). Large numbers of PV installations are noticed in The United States (US) within California, Arizona and Hawaii (Greentech Media and Solar Energy Industries Association, 2013). Other examples of DER rises are a significant growth of EVs in Norway – where EVs stood for 12.5% of new car sales in 2014 –California – with almost 130.000 plug-in vehicles on the roads by the end of 2014 – and CHP in Denmark (ABB, 2014; International Energy Agency, 2005; Lund and Münster, 2006).

On one hand, this DER development is positive due to reductions in CO_2 emissions with sustainable DG, decreased use of transmission lines, increased self-consumption and the increasing independence of customers from central grid power(Alanne and Saari, 2006). However, regardless of those, DER is potentially problematic for grid stability and reliability due to congestion and voltage issues (Eftekharnejad et al., 2012; Walling et al., 2008). These concerns are mostly posing effects on the distribution network, which is under supervision of the Distribution System Operator (DSO) in Europe or integrated service utility (in some places in the US). The German example shows that due to local electricity over production at the sunny moments of the day, reliability of supply is endangered in distribution grids (EPIA, 2014; EPRI, 2014; Yan et al., 2011). In France, realistic forecasts count on 450.000 Plug-in Electric Vehicles on the road by 2020 (RTE, 2014); if this objective is reached, simultaneous charging of these EVs could stand for between 5 to 20% of the annual peak load (RTE, 2014).

Existing research describes effects of DER penetration from both a technical and economic perspective. For example, (Eftekharnejad et al., 2012) and (Dang et al., 2015) discuss the impact of PV penetration on grid stability and the improvements that storage would provide. An holistic approach of DER management has been briefly discussed for the Norway sector (Ottesen, 2012). Possibilities exist to use the vehicle to grid systems for benefits of the overall electricity system as described by (Hota et al., 2014; Tan et al., 2016). Research highlights especially the difficulties for the DSO with increasing penetration of DER. The effects of DER on the financial position of the DSO has been presented (Ruester et al., 2014) together with the possible new roles of the DSO(EDSO, 2015; EvolvDSO, 2014). A approach on the way in which DSO charges should be set up to incorporate DER has been described(Cossent, 2013) as well as methods to remunerate DSOs with high penetration of DER (Jenkins and Pérez-Arriaga, 2014). Research showed that there are problems to be solved especially for distribution pricing (Li et al., 2015; Picciariello et al., 2015) and therefore an approach for such network tariff design with high DER penetration has been presented(Pérez-Arriaga and Bharatkumar, 2014).

DER can provide value in smart grids with their electric flexibility (Niesten and Alkemade, 2016), however a review of DER sources, their technical limitations for providing electric flexibility together with possibilities for economic trading of flexibility services is lacking. Consequently, this paper presents a review and classification of existing DER as flexibility providers and a detailed breakdown of trading platforms for DER in electricity markets.

Finally, this review ends with policy recommendations for management of electric flexibility from DER. Depending on system status and policy objectives, some arrangements might better serve system purposes than others. Due to its scope, this paper is of interest for policymakers in both liberalized and vertical integrated electricity sectors, next to electricity suppliers, network managers and emerging actors like aggregators and Energy Service Companies (ESCOs).

This paper starts with a description of general changes in the electricity system in Section 10.2. Section 10.3 presents a review of the most common distributed energy resources and their technical characteristics. Section 10.4 presents an overview of markets for flexibility trading. Next, Section 10.5 reviews incentives for DER management like tariffs, contracts and direct control. After, the discussion in Section 10.6 presents other important factors that should be taken into account for effective market design. Lastly, in Section 10.7 the conclusions are presented.

10.2 From Traditional to Smart Electricity Systems

The development from traditional to smart systems is seen world-wide, with examples in Europe (Faruqui et al., 2010), United States, China (Lin et al., 2013) , Australia (Haidar et al., 2015) and Brazil (Di Santo et al., 2015). These developments in electricity sectors challenge the traditional centralized management of electricity systems. The increased penetration of renewable energy sources (RES), the distribution of electricity production, the penetration of distributed energy resources and the move towards smart-metering and demand response call for a different approach on electricity consumption and production.

Supportive Feed-in-Tariffs in for example Germany incentivized the installation of small solar panels in the residential and commercial sector. In 2014 Germany had 38 GW capacity of Solar PV installed, with a large part, (more than 60%) located at low voltage levels (EPIA, 2014). Other examples of rapidly developing residential solar PV segment are found in

Belgium (where 1 out of 13 households are equipped with a PV system), Denmark, Greece and the United Kingdom (EPIA, 2014). Likewise, large numbers of PV installations are noticed in The United States (US) in California, Arizona and Hawaii (Greentech Media and Solar Energy Industries Association, 2013). Electricity generation is thus increasingly placed at the distribution grid as an alternative of at the transmission grid level. This affects the distributed nature of electricity generation (Alanne and Saari, 2006).

Demand response is a term that refers to “the changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized” (Aghaei and Alizadeh, 2013). Distributed energy resources (DER) e.g. Electric Vehicles (EVs), combined heat and power (CHP) units, electric water heaters and storage units are potentially providers of flexibility services, also referred to as demand response (DR). Different from the traditional view of electricity use at the distribution level, residential electricity consumers could be activated to respond on a trigger, which could be for example a price. In order to enable DER participation with the provision of demand response, smart metering together with alternative contracting and pricing methods are important requirements (Faruqui et al., 2010; Geelen et al., 2013). Furthermore, from a technical perspective, investments in distributed intelligence, distributed automation and in-home energy management could further facilitate the efficient operations of appliances connected at the distribution grid. However, in this paper, we focus on incentive design that can affect the operations of different DER and the resulting business cases for DER flexibility provision.

Renewable energy resources create important system benefits if they replace conventional generation resulting in decreased overall emissions. However, for system operation, RES increases risks because of unpredictable production patterns due to their highly intermittent character. Therefore RES require flexibility services like back up generation to supply for balancing needs of the non-supplied demand. Next to those traditional methods of system balancing, demand response and storage can potentially supply the system with flexibility services. Storage units are potentially beneficial for electric energy time-shift, power supply capacity and transmission congestion relief (Eyer and Corey, 2010).

Next to the previous named developments regarding the variability of RES generation, the distributed nature of generation and the change of demand from static to responsive, other developments affect the way in which distribution grids require decentralized management. An important one relates to the electrification of transport with the electric vehicle (EV). The EV development is important because EV charging may significantly increase electricity consumption at distribution grids during peak periods, potentially jeopardizing security of supply due to congestion and voltage issues (Clement-Nyns et al., 2011; Green eMotion, 2013).

10.3 Distributed Energy Resources as Flexibility Service Providers within Electricity Systems

As described in the previous section, Distributed Energy Resources (DER) e.g. Electric Vehicles (EVs), combined heat and power (CHP) units, electric water heaters and storage units are potentially providers of flexibility services. Technically, an electric flexibility service can be defined *as a **power adjustment** achieved at a given **moment** for a given **duration** from a **specific location*** within the network. Thus, a flexibility service is a service characterized by five attributes (see Figure 10.1): its *direction* (a); its *electrical composition* in power (b); its *temporal characteristics* defined by its *starting time* (c) and *duration* (d) and its base for *location*.

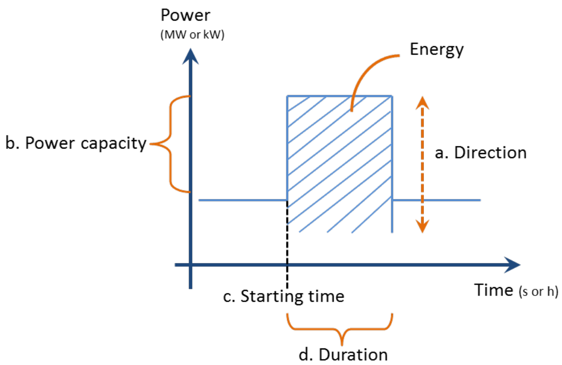

Figure 10.1: The attributes of an electric flexibility service (except for the attribute location) (Eid et al., 2015)

Some DER may have a single direction (for instance typical household loads, such as water heaters, dishwashers and electric heaters), while others have bidirectional capabilities and could both act as consuming and producing units (e.g. EVs and storage units).

Furthermore, the electrical composition is of importance in order to state for what system flexibility needs DER could serve, which calls for a differentiation between *power* and *energy* resources. The former have a rather low energy/power ratio. Those DER can provide the electricity system with a high power value, but are not able to maintain this power level for a long period of time. The latter have a high energy/power ratio and are more appropriate to maintain a change in power level for a longer period of time. The power resources are consequently better suited for short-term markets (e.g. on the ancillary service markets) while energy resources are better suited for long-term markets like balancing mechanisms and trading DR in the bulk electricity market.

In order to compare the different DER on this criterion, we define the *max power temporal ratio* t_r (expressed in time) as the maximum duration a DER can sustain its maximum power variation with respect to its nominal power. For some DER types, this parameter can be computed by dividing the allowed energy range by the maximum power capacity (e.g.

considering a stationary battery with a charging/discharging power equal to 10 kW and an energy capacity equal to 50 kWh, we find t_r = 5h). For some other DER, it may be related to physical characteristics (for instance for a water heater with thermic inertia, we may find t_r = 30 min). The lower this value, the more the DER can be considered as a *capacity type* DER, and vice-versa. This variable is intended to provide insights on differences between DER categories, although there is not a singular value for all DER in such category, simply because this is technology specific. Obviously, individual power and energy ratings are also of paramount importance; they will characterize the contributions of each individual DER. However, because DER will be gathered into aggregations to provide grid services, we find that t_r is more insightful to characterize DER abilities to provide capacity- or energy- related grid services.

Furthermore, the availability (in time) is a constraint that distinguishes the average number of hours during which DER could provide services to the system. Some resources may only be available during specific periods of time – for instance EVs are most likely to be available from 6 PM to 6 AM. In order to compare the flexibility providing units on this criterion, we compute for each of the DER the ratio a_r defined as the average number of hours during which the unit is available divided by the total number of hours in a week. As for the previous criteria, we aim to provide insights in expected values to compare different DER, although in reality similar DER may offer different availability times. Besides the average availability over one week, the specific period of time when the DER is available is also a crucial parameter. However, because this criterion is case dependent on the respective end user, we are not able to provide representative general estimations for this parameter.

Additionally, the activation time refers to the aspect that some resources may be able to adjust their power much quicker than other sources. Generally, almost all electric appliances have a fast activation time, ranging from the order of a second to one minute, except for CHP units which have longer ramping times (Houwing et al., 2010). Lastly, the location of DER is of importance for the supplied nature of the required demand response. For example, locational specific demand response could be of interest for local congestion management or distributed generation (DG) optimization. Table 10.1 provides an overview of common DER and their characteristics. The table is divided in different types of DER; consumption, bi-directional and generation.

	DER	Flexibility direction	Flexibility characteristic (power vs energy)	Availability ratio	Predic-tability	Technical response time	Grid[18]	Ref.
Electrical Consumption	Lighting loads (W)	Unidirectional (downward)	New LED systems: energy types older lightings: power types	$0.2 < a_r < 0.5$ during peak hours	Good	Second	DS	(Lee et al., 2011; Lu et al., 2008; Samarakoon et al., 2012)
	Dispatchable, residential loads (washing machines, dishwasher)	Unidirectional (downward)	Power type $5s < t_r < 5min$	$a_r < 0.1$ low *max power ratios* t_r due to max off time	High	Second	DS	(Lu et al., 2008; Samarakoon et al., 2012)
	Electrical heating/ Cooling (continuous loads)	Unidirectional (downward)	Power type $t_r \approx 15min$	$0.4 < a_r < 1$	High	Second	DS	(Samarakoon et al., 2012; Tomiyama et al., 1998)
Bi-directional	Electrochemical Energy Storage (EES) (kW-MW)	Bidirectional	Power & Energy types $4s < t_r < 10h$	$a_r \approx 1$	Perfect	Second to Minute	DS or TS	(Divya and Østergaard, 2009; Yang et al., 2011)
	Electric Vehicle (kW)	Unidirectional or Bidirectional	Power & Energy types 30 min < t_r < 6 h	$0.5 < a_r < 0.9$	High	Second	DS	(Kempton et al., 2009; Pearre et al., 2011)
Generation	PV Unit	Unidirectional (Upward)	Curtailable	$0.25 < a_r < 0.4$	Good a few hours ahead	Minute	DS	(International Energy Agency, 2013)
	Micro-CHP unit (kW)	Unidirectional (production mode)	Energy type	$a_r \approx 1$	Perfect	Rather slow (5%/min)	DS	(Houwing et al., 2010)

Table 10.1: Different DER and their technical characteristics

10.4 Consuming DER: Residential Loads

New generation LED lightings could adapt their power consumption to required grid power variations (Lee et al., 2011). Future LED systems could undergo system power variations up to 35% while humans would only perceive a variation of 15% in light intensity (Lee et al., 2011). This method would be particularly interesting for public lighting. On the contrary, older lighting systems do not have the same abilities (Lee et al., 2011; Samarakoon et al., 2012), since changing their power consumption would have serious impact on their luminous capability. LED lighting systems can maintain this power variation for a significant period of time and therefore can be considered as *energy type* flexibility resources. However, their potential power modulation is relatively low in absolute values – LED lighting bulbs consume

[18] Where DS stands for distribution grid and TS for transmission grid

75% less energy than conventional bulbs (DOE, 2006). Their predictability is relatively good (for instance public lighting has very precise operating hours), while their availability highly depends on the usage considered. Typical lightings would be turned on from a few hours a day during peak hours to 12 hours a day, thus we find $0.2 < a_r < 0.5$. It is noticeable that this criterion is highly seasonal dependent.

Residential appliances, such as water heaters, washing machines, electrical heaters and air conditioners have rather low *max power temporal ratios* t_r; changing the power consumption of most of these units impacts their primary usage. The latter can range from a few seconds (e.g. for cookers) to about a dozen of minutes (electric space heaters) (Samarakoon et al., 2012), thus providing a *maximum temporal ratio* of $5s < t_r < 15min$. Their availability depends a lot on the appliance considered: whereas electric space heaters have a good availability ($0.4 < a_r < 1$) due to the fact that they are turned on for long periods of time, washing machines have a very limited one ($a_r < 0.1$) as they are typically turned on once every two days for two hours (Hamidi et al., 2009; Roscoe and Ault, 2010). Similar rationale applies for their predictability (Tomiyama et al., 1998; Wong and Pelland, 2013). Heat pumps coupled with thermal energy storage stand out in this category; their *max power temporal ratio* can reach up to 3h without any inconvenience for end-users (Arteconi et al., 2013), making those units suited for longer grid services such as peak shaving.

10.5 Bi-directional DER: Electrochemical Storage and EVs

Storage units are potentially beneficial for electric energy time-shift, power supply capacity and transmission congestion relief (Eyer and Corey, 2010). Electrochemical Energy Storage (EES) units have a perfect availability and predictability ($a_r \approx 1$). Whether they should be considered as *energy type* or *power type* resources depend on their power density and energy density characteristics, both parameters being much related to the type of battery technology, e.g., Li-ion, Ni-MH and Ni-Cd (Yang et al., 2011). Thus, it is possible to find EES units for all kind of applications, from very-fast high-power responding units (such as supercapacitors, $t_r \approx 4s$) to energy type chemical batteries (such as Li-ion batteries, $t_r \approx 10h$)(Yang et al., 2011).

Most Electric Vehicles[19] that are on the roads today have a battery capacity around 20 kWh[20]. Their *max power temporal ratio* depends on the power of the charging station they are plugged in. Typical charging station powers range from 3kW to 50kW, leading to

[19] EV market share is today rather low everywhere (except in Norway): this is mainly due to their limited driving range, their high prices and the lack of charging infrastructure. However, these three barriers could be overcome in the near future, with the joint action of technology improvements and public policies.

[20] Nissan Leaf: 24kWh; Renault Zoe: 22kWh; BMW i3: 19kWh. In the future, battery characteristics are expected to increase significantly, what could change the value of EVs as DER.

approximately 30 min < t_r < 6 h. Because EVs are primarily used for transportation, capacity type services that would not empty the battery should be encouraged. Privately owned EVs are mainly available during nighttime and weekends ($a_r \approx 0.5$), but the availability could rise up to $a_r > 0.9$ if charging points are installed at working places. Company fleets have slightly different usage patterns and could also be available in the afternoons ($a_r \approx 0.8$). EVs predictability patterns are easily foreseeable (Pearre et al., 2011), especially considering a fleet of EVs and not a single vehicle.

10.6 Producing DER: Micro CHP and PV Units

Micro-CHP units are small heat and electricity generating entities. They have a large availability and predictability since they are dedicated to heat and electricity production ($a_r \approx 1$). It is more difficult to define a *max power temporal ratio* for micro-CHP units because they could produce electricity at maximum power continuously, as far as they are being supplied in primary energy source (mainly gas). Rather, their availability to maintain a change in their electricity production will be based on economics considerations. The control strategies of micro-CHP units are likely to take into account energy costs (Houwing et al., 2010) in their economic balance. Therefore, micro-CHP units would fit in the *energy type* category.

PV units are different from the others, in the sense that their production output cannot be controlled – however, with the introduction of smart inverters, PV production can be curtailable and, considering aggregation across multiple sites, PV aggregations could even provide downward and upward reserves. The units produce electricity between 6 and 10 hours a day depending on their location. Generally production forecasts can be achieved a few hours ahead (International Energy Agency, 2013) for single units. However, the predictability improves for aggregations of many solar units rather than individual units (similar to EV fleets as discussed above).

10.7 Markets for Electric Flexibility Trading

Traditional electricity systems are managed in a top-down manner, meaning that generally large generation units connected at high voltage levels feed in electricity for electricity consumers that are located at all other voltage levels. Flexible generation units (mostly hydro units, gas and coal fired power plants) are besides providers of bulk electricity supply, also providers of electric flexibility by means of upward and downwards adjustments. Those adjustments could be incentivized by for example capacity contracts with the System Operator (SO) for automatic adjustments.

Besides generation, also consuming units might be suppliers of electric flexibility. In the United States demand response is largely used in many markets, for example with the Regional Transmission Operator (RTO) of Pennsylvania-New Jersey and Maryland, shortly named PJM (PJM, 2014). France and the United Kingdom (UK) are important frontrunners in Europe regarding developments with demand response (SEDC, 2014). In France, already before sector liberalization, demand response activity was triggered by the electricity utility EDF for industrial electricity customers. These units received dynamic tariffs that incentivized consumption shifting. Table 10.2 provides an overview of the most common traditional markets for electricity trading in the short and long term, based on the French trading time periods. The next sections describe in further detail examples of demand side flexibility that is allowed in flexibility trading worldwide. Please note that the examples presented here are not meant as an exhaustive review, rather as representative examples. There are more existing examples than those presented markets for DER participation in system flexibility.

10.8 DER Trading for Ancillary Services

Ancillary service markets are in place in order to manage transactions for upward or downward adjustments in the short to very short term. These markets are organized very close to real-time and require automated load adjustment. In France ancillary service markets are organized shorter than 30 seconds before real-time for Frequency Containment Reserves (FCR, also named primary reserve), below 15 minutes for Frequency Restoration Reserves (FRR, also named secondary reserve) and lastly Replacement Reserves (RR, tertiary reserve) for system balancing between 13min-2h before real time (see Table 10.2). In the United States (US) and UK numerous projects present examples of DER flexibility provision within ancillary service markets (dynamicDemand, 2005; Kempton et al., 2009). Due to the fact that individual DER do not provide sufficient reliable electric flexibility to be tradable in markets, aggregation is required in order to trade in organized markets. In the US, the REG-D (Dynamic Regulation) signal is used for activating fast responding resources like flywheels and stationary batteries(PJM, 2015c, 2013a). Furthermore, within the Delaware EV project this signal is used for activation flexibility from aggregated EVs. In this project an EV aggregator acts as an intermediary firm between PJM (the regional transmission operator) and flexibility service providing EVs. This aggregator sells a certain amount of capacity to the grid operator and bids this in the hourly auction for frequency regulation and for the available power capacity ($/MWh) (Kempton, 2014; Kempton et al., 2009). When participating in the frequency regulation market, EVs receive the REG-D dispatch signal from PJM and are remunerated accordingly. If the regulation service offered by the Delaware EV aggregator has not met with the performance thresholds over a specified time period in terms of correlation (delay) and precision, PJM is allowed to penalize and disqualify the aggregator (Chris, 2013).

10.9 DER Trading for System Balancing and Network Congestion Management

Markets for balancing services are arranged longer before real-time than ancillary services and do allow aggregated flexibility resources to participate in places in the United States and Europe. In the US, for example, through the Boston based aggregator EnerNOC, demand response suppliers can trade their flexibility in balancing markets (Chris, 2013). In Germany, many industrial loads are directly participating in the balancing mechanism; however, for aggregated loads still many barriers exist to participate within the balancing markets (Koliou et al., 2014). In the French system such barriers have been lowered by the reduction of the minimum bidding capacities for balancing services from 50 to 10 MW in order to motivate the entrance of smaller entities like aggregators to participate in balancing mechanisms(SEDC, 2014).

Differently, for network congestion management a French example of small load aggregation is the aggregator named Voltalis[21]. Customers contracted with Voltalis receive a free box installed in their home named Bluepod, which reduces their electric heating device operation in short time intervals when Voltalis receives a signal from the TSO. The dispatch signal is mostly related to endangered electricity supply sufficiency in Brittany (a poorly interconnected French region) and network limitations. Customers who have the box installed are automatically enrolled, but can opt-out at any time by pushing a button on the device and use their electric heater as usually. Voltalis as an aggregator is able to trade the aggregated flexibility in different markets like balancing markets and demand response mechanisms of the TSO. The customers observe a reduction of their normal electricity bill due to those interruptions in electricity consumption for heating, however do not receive extra payment for their provided flexibility.

In Sweden the DSO can incentivize load shifts by the provision of Time of Use (TOU) prices in order to defer network investments or decrease congestion by incentivizing the customer to shift the load away from peak moments (Bartusch et al., 2011; Bartusch and Alvehag, 2014). Different from the previous examples, the DSO does not trade this flexibility within a market for congestion management or deferred network investments, but this is a direct incentive arrangement between the DSO and electricity users.

10.10 DER Trading in Spot Markets and Generation Capacity Markets

In the United States, demand resources can also participate in wholesale and capacity markets. A Curtailment Service Provider (CSP) is the entity responsible for DR activity for electricity consumers in the PJM wholesale markets(PJM, 2013b). Demand response was growing relatively quickly due to supportive Order 745 which settled prices for demand response equal to that for generation in wholesale electricity markets [49]. DR is a major supplier of capacity in most U.S. capacity markets like PJM, ISO-NE, NY-ISO(FERC, 2015b; PJM, 2015d, 2014).

As the first one in Europe, the French system provides a possibility for demand response trading within spot markets. This is possible since 2014 wherein demand response can be

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[21] Information on Voltalis via: www.voltalis.fr

traded in the day-ahead market through the NEBEF mechanism[22]. In 2017 it is foreseen that DR will also be tradable in capacity markets in France (RTE, 2013b). Furthermore, the French TSO organizes an annual tender dedicated specifically to DR providers.

10.11 Incentives for Efficient Operation of Distributed Energy Resources

Price signals can play an important role in incentivizing efficient interactions from network users (Pérez-Arriaga and Bharatkumar, 2014). The literature of tariff design shows the complexity of incentivizing efficient interactions however, due to the many different principles that should be taken into account. Those principles include efficiency, equity, simplicity, consistency, transparency, stability and additivity (Green and Pardina, 1999; Leveque, 2003; Reneses and Rodríguez Ortega, 2014). Possibilities with smart metering and real-time pricing allow for the increase of cost causality with tariff design, meaning that the electricity prices reflect the actual costs that are being occurred when delivering the service. A number of approaches have dealt with this topic during the last years, considering the impact of an increasing deployment of DER (Li and Tolley, 2007; Mutale et al., 2007; Pérez-Arriaga and Bharatkumar, 2014; Picciariello et al., 2015; Ruester et al., 2014; Sotkiewicz and Vignolo, 2007). However, dynamic prices could result in trade-offs for the stability and transparency principles of the tariffs for residential users. Therefore, for frequently changing prices, it could be preferred to use direct control or automation in order to increase reliability of the demand responsiveness. Furthermore, due to the fact that each DER has its own technical requirements and abilities to provide flexibility services, a non-singular approach is suggested; rather, a combination of for example tariffs, contracts and direct control should be considered.

Broadly speaking, a distinction is made between **price based** and **controllable** methods for demand response, also referred to as price based and interruptible demand response (Muratori et al., 2014) or as direct and indirect methods of load modification. Next to tariffs therefore, direct control and other contract arrangements are methods by which efficient operation of DER could be incentivized.

[22] See https://clients.rte-france.com/lang/fr/clients_distributeurs/services_clients/effacements.jsp

Time frame	Technical system flex need	Trading mechanism	Capacity or Energy trade?	Notification[23] <u>before real time</u>	Suited DER type	Location[24] DER connection	Examples of DER trading/incentive in traditional centralized markets
	Ancillary Services	Primary Reserves (FCR)	Capacity	<30s (automatic)	EV's, residential loads, continuous loads, EES	Transmission and Distribution	UK: Demand Response with dynamically- controlled refrigerators (dynamicDemand, 2005)
		Secondary Reserves (FRR)	Capacity	<15 minutes (automatic)	EV's, residential continuous loads, electrical heating, EES	Transmission and Distribution	USA: EVs and stationary batteries for frequency regulation in PJM (Kempton et al., 2009; PJM, 2015c)
	System balancing	Balancing mechanism (Tertiary reserves, RR)	Energy and/or Capacity	13 min - 2 h	EV's, EES, CHP units	Transmission and Distribution	Germany: industrial loads participate in balancing mechanism (Koliou et al., 2014) USA: aggregators can trade flexibility in balancing markets [43]
	Network constraints / Network capacity planning	Transmission congestion management	Energy	13 min - 2 h with balancing mechanism or separate	large EV coalitions, EES, CHP units	Transmission and Distribution	France: congestion management is traded in balancing market (CRE, 2015) And the Voltalis load management of residential heating devices (Eid et al., 2015)
←←← Short Term		Distribution congestion management	Energy or Capacity	No dedicated market found	EV's, residential loads, electrical heating, EES	Distribution	Sweden: distribution Time-of-Use pricing for residential users. (Bartusch et al., 2011)
	Spot market energy trading	Intraday market	Energy	1 - 24 h	Aggregated loads	Transmission and Distribution	Elbas intra-day market (Nordic region) opened to DR (Andersen et al., 2006)
Medium Term		Day ahead market	Energy	24 - 48 h	Aggregated loads	Transmission and Distribution	France: The NEBEF mechanism allows trading of DR in spot market (RTE, 2013a) USA: Some wholesale markets allow DR trading, such as in PJM (Mcanany, 2014)
←←←	Generation Capacity planning	Capacity Market	Capacity	Year ahead	Aggregated loads	Transmission and Distribution	USA: DR is participating in capacity markets in PJM, ISO-NE, NY-ISO (FERC, 2015c; PJM, 2015d) France: DR trading in capacity markets is foreseen in 2017. (RTE, 2013b)
Long Term		Capacity Payments	Capacity	Year ahead	Aggregated loads	Transmission and Distribution	No evidence found.

Table 10.2: Markets for electric flexibility trading related to DER possibilities

[23] Note that these time values relate to the French system and can be different elsewhere.
[24] This paper focused mainly on flexibility provision from DER connected at distribution level. However if no example of DER flexibility provision at the distribution level was found for specific markets, the table presents examples of large industrial units for this purpose.

10.12 Price Based Methods for DER Management

Price-based demand response is incentivized by exposing the DER owner to a time-varying electricity rate, also called a dynamic rate. The theory of dynamic tariffs for demand response has already been discussed in 1989 by David and Lee for large industrial electricity users (David and Lee, 1989). Table 10.3 presents an overview of those tariff options with definitions. In this table, a distinction is made between basic dynamic pricing options and those that specifically incentivize adjustments of users' normal consumption patterns (also called baseline consumption adjustments). The basic pricing options leave more freedom to the user, without requiring extra information on baseline consumption levels. Options for such pricing methods are 1) Time-of-Use pricing (TOU), 2) Real-Time Pricing (RTP) and 3) Critical Peak Pricing (CPP). An extreme and one-sided economic approach on settlement of incentives for DER management would be the application of real-time nodal pricing that would incorporate both grid and supply constraints at each moment in time, incentivizing upward or downward adjustments for all DER(Sotkiewicz and Vignolo, 2006).

Furthermore, the more specific incentives for baseline adjustments are 4) Peak Time Rebates (PTR), 5) Interruptible capacity programs (ICAP) and 6) Emergency demand response (Newsham and Bowker, 2010). Those options require baseline consumption information penalizing or remunerating for specific load adjustments. With RTP, the user receives a changing price per time step (for example 15 minutes) and the customer will shift electricity consumption accordingly. With critical peak pricing, only in specific hours per day a higher price is presented to the customer. Electricity customers receive an ex-ante notification of these moments in time and can therefore plan their consumption (Koliou et al., 2013). Critical peak pricing together with the options for baseline adjustments are specifically incentivizing the shift of electricity consumption away from a specific moment in time. A driver for such incentives could relate to, for example, high wh0olesale market prices or jeopardized system reliability (Koliou et al., 2013).

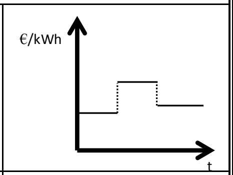
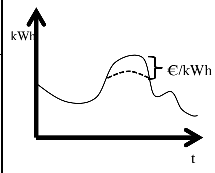
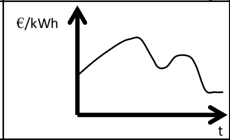
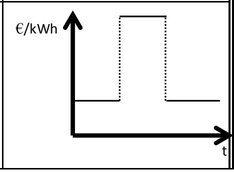
Basic dynamic pricing options			Specific incentives for baseline adjustment		
Time-Of-Use (TOU)	Fixed electricity prices for different time blocks within a time period		**Peak time rebates (PTR)**	A rebate when electricity is reduced compared to baseline consumption, within certain hours in a year.	
Real-Time-Pricing (RTP)	An hourly rate depending on the day ahead real-time price of electricity		**Interruptible Capacity Program (ICAP), Interruptible load**	A rebate when electricity is reduced below a baseline value.	
Critical Peak Pricing (CPP)	High electricity price periods for certain (fixed) days of time within a year		**Emergency Demand Response**	Mandatory commitment to reduce load, with penalties if not supplied.	

Table 10.3: Possible dynamic pricing options for DER management (David and Lee, 1989; Faruqui and Sergici, 2009; Hakvoort and Koliou, 2014)

10.13 Direct Load Control for DER Management

Different from the price based approaches in Section 10.12 where the customer is free to decide in real-time regarding the supply of flexibility, direct control methods are more contractual and introduce obligations for the flexibility supply(DOE, 2006). With controllable or incentive-based DR, the system operator, aggregator or even retailer could make the end user agree to automatically control (upward or downward) the operation of the DER appliance. This control could be price driven, like in wholesale or balancing market trading of flexibility. Differently, this could be directly to avoid reliability problems like network congestions [30]. In the PJM market, direct control is managed by the curtailment service provider [50]. This means that a central actor has direct access to the load and is able to reduce or increase this as required for the system and/or for portfolio management purposes. Load shedding refers to the “switching off” of entire network zones from electricity supply in order to sustain total system operation (Newsham and Bowker, 2010). With brown outs, the system operator slightly reduces frequency in order to reduce the needed electricity transport capacity and generation capacity but to maintain electricity supply quality within limitations (Blume, 2007). Consequently, direct control methods are probably more suited for short-term provision of flexibility services and services which require a very precise location of activation like voltage control and congestion management. Table 10.4 provides an overview of different incentives presented and relates them to their suitability to DER types and markets for flexibility.

10.14 Techno-economic Alignment of Incentives

Depending on the type of DER, certain incentive or control might be appropriate to support interactions that take into account the technical attributes of the DER flexibility. Taking into account the technical activation time of DER and possible incentives, Table 10.4 provides an overview of appropriate incentives or control methods within existing trading platforms for trading DER flexibility. For grid interactions which require response between 1 to 30 minutes before real-time, direct load control would be suited in order to secure response of this DER. Appropriate DER for such short notification time periods would be most DER except for CHP units due to their longer ramp-up times, although *capacity-type* DERs would be more efficient than *energy-type* DERs. Furthermore, PV units would not be dispatchable due to their generation dependence on weather conditions; however, in combination with storage flexibility trading could be enabled. For longer notification times of 30 min to 1 hour, all other pricing methods could be suited and decisions should be further dependent on socio-economic factors like user characteristics of price elasticity and the availability of home automation. All DER types would be appropriate for supplying flexibility for longer than 1 hour of activation time, except for short-term duration batteries or other short-term energy storage. For the very long term, critical peak pricing and time of use pricing are appropriate due to the possibility to settle those prices on a yearly basis, as this is the case in France with the tempo tariff[25]. Similarly, contractual arrangements are also appropriate for long-term capacity products, as done under PJM regulation (Mcanany, 2014).

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[25] See http://residential.edf.com/energy-at-home/offers/electricity/tarif-bleu-56121.html

Notification time before real-time	Appropriate incentives or control method for DER management	Related markets for electric flexibility trading[26]	Appropriate DER
< One minute	Direct control	Frequency control (primary, secondary, tertiary reserves), voltage control	*EV, Continuous loads (heating/cooling, lightning), EES*
1-15 minutes	Direct control	Network restoration, voltage control	*EV, Continuous loads (heating/cooling) , EES*
15-30 min	Direct control	Network restoration (HV/LV), Balancing market, Portfolio balancing	*EV, EES, CHP units Continuous loads (heating/cooling), dispatchable loads*
1 hour	Direct control, ICAP, Emergency demand response, Real time pricing, Peak time rebates, Critical Peak Pricing	Balancing market, Network Congestion Management	*EV, EES, CHP units Continuous loads (heating/cooling), dispatchable loads*
1-48 hour	Direct control, ICAP, Emergency demand response, Real time pricing, Peak time rebates, Critical Peak Pricing	Spot Market (Day ahead and Intraday market)	*EV, EES, CHP units Continuous loads (heating/cooling), dispatchable loads, PV units with storage*
Year ahead	Critical peak pricing, Time of use pricing	Deferring network investments (HV/LV), generation investment peak reduction	*EV, EES, CHP units Continuous loads (heating/cooling), dispatchable loads, PV units with storage*

Table 10.4: Relationship between notification times, appropriate incentives and markets for DER flexibility trading

10.15 Discussion

This paper has provided an overview of DER and their technical abilities to provide flexibility services for system needs. The effective use of flexibility from DER requires taking their technical characteristics into account and those of the existing trading platforms. However, the practical usefulness of incentive design is strongly dependent on socio-economic factors. Examples of such aspects are normal consumption/production patterns, perspectives on sustainability, investment costs for enabling technologies like smart metering and in-home automation, and the price elasticity of the end user or DER from whom flexibility is being demanded (Goulden et al., 2014). When designing effective incentives for flexibility from for example EVs or privately owned CHP units, socio-economic factors are of crucial importance.

[26] Composed with insight from report (International Energy, 2008).

10.16 The Transition towards Decentralized System Operation

Besides the socio-economic context, also the regulatory environment of the electricity system at stake will affect the decisions for appropriate signals for flexibility. Flexibility trading options shown in this paper are all presented in the framework of centralized system management, generally under responsibility of the system operator. However, decentralized management approach could open up possibilities for locational pricing, local balancing and optimization at the distribution level (Alanne and Saari, 2006; Kamat et al., 2002; Pudjianto et al., 2007). Consequently, DER penetration could call for alternative trading models that focus on efficient flexibility trading for electricity flows at the lower distribution levels. Attempts have already been done with for example a model with the use of an aggregator (Niesten and Alkemade, 2016). Besides the fact that decentralized management would yield benefits from more cost-causality based incentives, it could also encourage a new approach on consumption, moving from "*passive energy consumer*" towards an "*active energy citizen*" (Goulden et al., 2014). Therefore, the use of centralized markets for DER management might be seen as a transition phase towards possibly a decentralized techno-economic management approach of the electricity system(Orehounig et al., 2015; Schmid et al., 2016). Figure 10.2 presents a conceptual presentation of the arrangement of such a decentralized system based on possible system challenges and opportunities with DER integration.

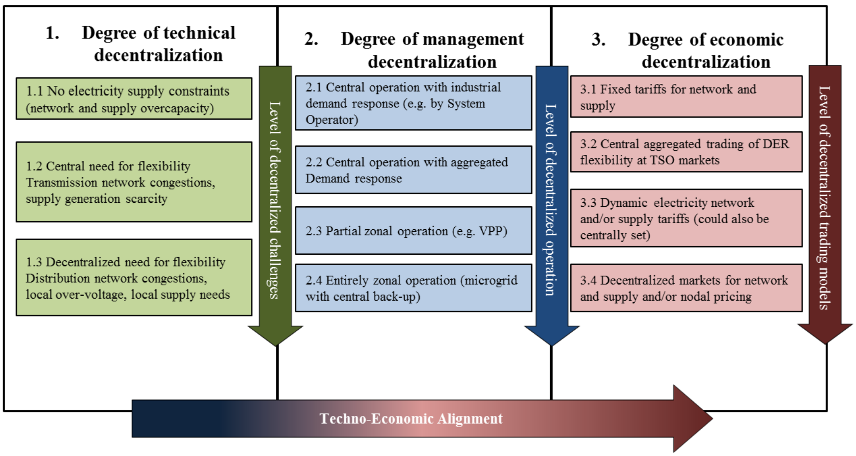

Figure 10.2: Techno-Economic alignment of decentralization in electricity markets

10.17 Settlement of Incentives and Control: Which Roles for Different Actors?

Depending on the electricity market design and the level of sector liberalization, one or more of the actors in the sector could decide on (dynamic) tariffs, direct control and other flexibility enabling methods. Insights in the role(s) of the DSO, electricity retailer, supplier, (independent) aggregator and third parties are crucial to effective incentive design. Some challenges that arise have never been dealt with before, as for example the ones related to load aggregation. Due to the fact that there are minimum trading values for the balancing and other free markets, DER should be bundled to simultaneously provide significant tradable amounts of flexibility in those other markets. However, when aggregation is done by independent actors, this could compete with balance responsibility programs of electricity suppliers from whom the initial electricity was procured(Eurelectric, 2015). Furthermore, it should be taken into account that multiple actors could want to procure flexibility at the same time for a different direction. This for example is the case when the network is congested, however the electricity prices are low. Thus, cooperation between TSOs and DSOs, and DSOs with retailers or other market parties should be improved, so that simultaneous procurements of flexibility services would not happen to be counterproductive. Therefore, enabling flexibility from distributed energy resources requires an holistic perspective of roles and responsibility. An approach for this has been presented with the Universal Smart Energy Framework (USEF) (Eurelectric, 2015) [27].

10.18 Conclusions

This paper presented a review of existing Distributed Energy Resources' (DER) abilities to provide flexibility services and reviewed options to incentivize this service provision. With a central management approach on electricity systems, flexibility services from DER could be traded within traditional markets for securing reliability of supply. Due to the fact that each flexibility source has its own technical abilities to provide flexibility services, the authors of this paper argue that utilization of DER flexibility services require a non-singular approach. Depending on the type of DER, therefore also a difference should be made between the appropriate signals, which could be a combination of tariffs, contracts and direct control. Next to the central utilization of DER flexibility services in traditional markets (like for ancillary services, balancing, and spot markets), also decentralized management of DER could be possible through for example local markets or local aggregation and optimization (See Figure 10.2). The interest for this type of management is arising, especially due to upcoming risks due to over-voltage and congestions with the penetration of distributed generation (DG) (Eftekharnejad et al., 2012; Walling et al., 2008). Possibilities increase for such alternative management methods with the roll-out of smart meters, distributed automation and control (Faruqui et al., 2010).

In this paper we focused on the provision of electric flexibility through already existing electricity markets. Even though in many places aggregated flexibility trading is possible, in many places this is still not the case due to regulatory barriers due to the fact that flexibility markets were historically designed for large power producers or large industrial consumers. In order to allow aggregation of DER, policy should assist to lower those barriers and arrange compensation mechanisms between aggregators and electricity suppliers (Eurelectric, 2015). However, further developments could allow for flexibility trading not only at central markets, but also at local levels in which locational needs for flexibility could react to for

[27] For the complete documentation of this framework, see www.usef.org

network capacity problems (Burger et al., 2001). Questions that remain open are weather there should be one central aggregator or multiple aggregators for providing such services (Niesten and Alkemade, 2016). A very ambitious techno-economic approach on settlement of signals for DER management could be based on a nodal pricing mechanisms that would incorporate both grid and supply constraints at local levels (Sotkiewicz and Vignolo, 2006). However differently from transmission levels, this approach currently does not seem viable due to the passive management of distribution grids (Ruester et al., 2014).

Therefore, future work should be done to include socio-economic factors within developments of new models for flexibility management at local network levels. Socio-economic factors include consumption or production patterns, the consumer perspectives on sustainability, investment costs for enabling technologies like smart metering and in-home automation and the price elasticity of the end user or DER from whom flexibility is being demanded. Furthermore, from a more automated and technical perspective of flexibility management research should give insight in cost-efficient optimal DER combinations to supply flexibility for specific technical system requirements. Not important is furthermore the roles of traditional and new actors in the development of flexibility management; especially when current regulation discourages the use of flexibility from local network users. Depending on the current and expected challenges in electricity systems, policy should anticipate the required DER transactions and incentivize arrangements and market models that will benefit the system from an economic, sustainability and reliability perspective.

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11 Published Paper III: Time-based Pricing and Electricity Demand Response: Existing Barriers and Next Steps

This paper is published in Utilities Policy (2016), issue 40, pages 15-25, by Eid, C., Koliou, E., Valles, M., Reneses, J., Hakvoort, R.

Highlights:

- Market coordination is crucial for the development of demand response in liberalized electricity markets
- Tariff design should differentiate between permanent and transient price signals
- Demand response is potentially competitive with incumbent power production

11.1 Introduction

Increasing penetration levels of intermittent renewable energy sources (RES) in power systems are imposing new challenges for policy makers and regulators. These renewable resources can be located at locations within both high-voltage and low-voltage grids. The penetration of distributed energy resources (DER), such as distributed generation (DG), electric storage and electric vehicles (EVs), significantly affect the operations of distribution grids (Pérez-Arriaga and Bharatkumar, 2014; Pudjianto et al., 2007). Ensuring reliable electricity supply in this context is costly endeavor given the requirement for back-up flexible electric power generation combined with limited electricity transmission capacity. Regulatory authorities are increasingly considering load flexibility, also known as demand response (DR), for enhancing system coordination. DR refers in general to the ability of the demand side to be flexible, responsive and adaptive to economic signals.

Adequate price signals reflect the actual costs of various electricity supply activities. In response to prices, demand-load modification could have a positive economic impact on society as a whole by stimulating efficiency electricity system operations and markets. In the medium and short term, the signaling of DR can result in the adjustments of loads to network capacity constraints in order to remain within technical limitations and diminish the possibility of a system collapse. Alternatively, in the long term, DR is useful for lowering both generation and network investment requirements and minimizing permanent grid congestion (Batlle and Rodilla, 2009).

In the US, interest in demand response rose in the early 1970s from the penetration of air conditioning in American homes, resulting in needle peaks and reduced load factors in system demand profiles. At this time, there was increasing recognition of rising system costs to meet the peaking loads, and utilities began to view load management as a reliability resource (Cappers et al., 2010; Koliou et al., 2014). After the passing of the Public Utilities Regulatory Policy Act (PURPA) in the early 1980s, measures designed to reduce demand peaks were set forth via the promotion of load-management programs. Those involved both direct-control and price-based programs for large industrial users (DOE, 2006). Similarly, in

Europe, large industrial customers provide demand response flexibility for balancing purposes in real-time system operation.

The value and necessity of DR is recognized by the European Commission. The Energy Efficiency Directive (EED), Art.15, explicitly urges EU national regulatory authorities to encourage demand-side resources, including DR, "to participate alongside supply in wholesale and retail markets", and also to provide balancing and ancillary services to network operators in a non-discriminatory manner (Directive 2012/27/EU). Furthermore, main European Policies advocating for DR to participate alongside supply in wholesale markets calling for aggregation are the Directives 2009/72/EC regarding common rules for the internal market in electricity, the ENTSO-E 2013 Demand Connection Code, and the ACER 2012 Framework Guidelines on Electricity Balancing. Hence, mechanisms for implementing DR are receiving increasing attention by European regulatory authorities and institutions (CEER, 2011). DR potential in the EU electricity markets is believed to be high but currently underutilized (European Commission, 2013b), especially for residential consumers, on account of current institutional arrangements that cater to large generators and industrial customers.

The deployment of smart meters and information and communication technology (ICT) infrastructure enables a paradigm shift in the way electricity systems are operated, transforming traditionally passive end-users into active market players (Eurelectric, 2011; European Commission, 2013b, 2012b; Giordano et al., 2011; Hancher et al., 2013). Different tariffs promote an array of incentives for customers to modify consumption profiles that, accordingly aid the system in achieving reliability objectives. Price dependent DR refers to financial incentives or penalties to motivate customers to provide load flexibility (Wang et al., 2010).

A range of options is available for designing and implementing electricity tariffs (Reneses and Rodríguez Ortega, 2014). Due to the indirect incentives that result from tariff design, different types of load flexibility can be expected from different pricing methods. Until now, time-based pricing has been applied mostly to incentivize large industrial users, leaving the approach unclear for residential customers. The literature on time-based pricing focuses on demand response to serve the objectives of electricity supply (Nieto, 2012), balancing (Koliou et al., 2014), and network purposes (Bartusch and Alvehag, 2014). Consideration of network design and grid constraints is gaining momentum, especially in systems with high penetration levels of renewable energy sources (RES, both distributed and large scale). Conchado et al. (2011) defined bilateral benefits for both network and generation purposes (Conchado et al., 2011). However, most of the literature does not take into account the parallel effect of time-based pricing on the final electricity bill of electricity users.

Therefore, a relevant contribution of this paper is an update to the state of the art, in which both theoretical framework and practical experiences are described for Europe. Furthermore, we describe contemporary challenges today and provide recommendations for how to overcome them via amendments to existing European legislations as well as lessons learned from other policy contexts.

The paper is structured as follows. Section 11.2 provides a theoretical description of DR and Section 11.3 presents the necessary elements of electricity billing for incentivizing DR. Next, Section 11.4 presents examples of time-based prices for demand response in Europe. Lastly, Section 11.5 outlines major barriers for DR activation followed by conclusions and policy recommendations in Section 11.6.

11.2 Definition of Demand Response

The literature provides various definitions of demand response, but a clear common theme is that DR reflects electricity demand that is intentionally responsive (flexible) to economic signals (see Table 11.1 for frequently cited DR definitions in the literature and policy documents). An important difference between demand response and demand-side management is that demand side management (DSM) can be seen as the over-arching concept that can encompass demand response (in addition to energy efficiency and electricity storage), driven by DSM adapters and policies (Warren, 2014).

Citation	Definition
Definition is an extension of IEA (2003), quoted from (Albadi and El-	*"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*
(Torriti et al., 2010)	*"Demand Response 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)."*
(Greening, 2010, p. 1519)	*"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."*
(ACER, 2012, p. 8)	*"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."*

Table 11.1: Frequently cited demand response definitions (Koliou, 2016)

In the US, as of 2014, DR programs alone were estimated to have a potential of 28,934 MW consequently accounting for 6.2% of the total peak demand (FERC, 2015). Within Europe, there are long standing arrangements or programs to involve energy-intensive industrial customers in DR (mostly through interruptible tariffs or time-of-use pricing), and some system operators make use of large avoided loads as part of their system balancing activities

(Torriti et al., 2010). Countries with large penetration of RES, such as Germany, currently use demand flexibility to maintain system-wide reliability (Koliou et al., 2014).

Conceptually, DR also can be defined as a flexibility service that is specified by (Eid et al., 2015):

- Direction (upward or downward);
- Size (kWh and kW);
- Time;
- Location (zone or node).

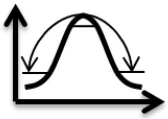
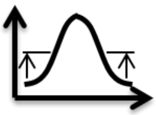
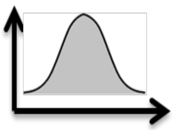
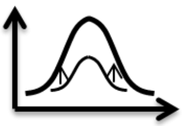
Load Shape	DR type	Load Shape	DR type
	*Peak Clipping*		*Load Shifting*
	*Valley Filling*		*Flexible load shapes (dynamic energy management)*
	*Load Building (Strategic Load Growth)*		*Strategic Conservation (energy efficiency)*

Table 11.2: Adjusted load shapes as a result of DSM (Chuang and Gellings, 2008; Gellings, 1985; Hakvoort and Koliou, 2014)

For example, an electricity network with congestion issues requires location-specific demand flexibility. When demand responsiveness is aimed at sustaining system balance via market arrangements, the location of DR is of less importance than the aggregated direction, size, and timing.

11.3 Types of DR and Effects on the Electricity System

Demand-side management programs could be aimed toward modifying traditional electricity demand in different ways (see Table 11.2 for a visual presentation of the types of adjusted load shapes). Demand response that is aimed at decreasing consumption during peak times can be categorized as peak clipping. Load shifting is mostly associated with usage reduction at peak that is offset by usage in off-peak hours. DR that is aimed at increasing consumption levels (for example at times with high renewable energy production) can be categorized as valley filling, load building, or flexible load.

11.4 Benefits of Demand Response to the Electricity System

The potential benefits of DR rest upon the energy policy pillars associated with economic, environmental, and reliability objectives (see Aghaei and Alizadeh, 2013). Economic or market-driven DR reduces the general cost of energy supply while preserving adequate reserve margins and mitigating price volatility by means of short-term responses to electricity market conditions. Environmental-driven DR would serve environmental and social purposes by decreasing energy usage, increasing energy efficiency, defining commitment to environmentally friendly generation, and reducing greenhouse gas emissions. Lastly, network-driven DR aims to maintain system reliability by decreasing demand in a short period of time and reducing the need to enhance generation or transmission capacity.

Batlle and Rodilla classify DR benefits in accordance with time. For the short and medium terms, DR would decrease network peak and risk of system collapse by keeping electricity flows within technical constraints. In the long term, DR could decrease generation and network investment needs, relieve regular congestion, and increase energy efficiency (Batlle and Rodilla, 2009).

In this work we define additional DR benefits from a technical system perspective based on alignment with time-based pricing. Koliou and Hakvoort (2014) describe DR objectives associated with day-ahead optimization, hour-ahead optimization, network peak reduction, local balancing, real-time control, DG optimization and central RES optimization. Secondary forthcoming effects include CO2 reduction and decreased need for distribution and transmission network investments. As discussed beforesmaller, residential demand flexibility must be aggregated before in order to be eligible for trade in central markets (such as balancing markets). The aggregation function can be provided by an independent aggregator, an electricity retailer, or even the network operator.

11.5 Activation of Demand Response

There are different ways to activate DR in the electricity system. Broadly speaking, a distinction is made between “controllable” (interruptible) and “price-based” DR (Pfeifenberger and Hajos, 2011; Muratori et al., 2014) also referred to as direct control and indirect methods of load modification, respectively.

Direct methods or controlled DR are applied in order to sustain electricity supply reliability. These methods include direct load control (DLC), load shedding, and intentional brown outs. Direct load control simply means that a central actor (such as a system operator, aggregator, or balancing authority) has direct access to the load and is able to make adjustments as required by the system. Load shedding refers to the reduction of electricity consumption in network zones in order to sustain total system reliability (Newsham and Bowker, 2010). With brown outs, the system operator slightly reduces voltage frequency in order reduce the needed electricity transport capacity and generation capacity while still maintaining electricity supply quality within limitations (Blume, 2007). Direct methods for DR are contract-based and therefore provide secure flexibility in time and place for the system operator based on central control.

Price-based DR refers to "changes in electric usage by end-use customers from normal consumption patterns in response to changes in the price of electricity over time" (DOE, 2006). The theory of price-based DR for large industrial electricity users was discussed by David and Lee (1989). Pricing options include real-time pricing (RTP), critical-peak pricing (CPP), time-of-use pricing (TOU), and peak-time rebates (PTR) (Newsham and Bowker, 2010 ; see Table 11.3). Drivers for such rates could be high wholesale market prices or factors that jeopardize system reliability (Koliou et al., 2013).

Price changes are more frequent in RTP than in TOU pricing. For example, real-time prices might adjust on hourly basis, while TOU prices might be adjusted for time blocks during the day (for example four-hour periods). With CPP, the utility can on short notice set a higher price to incentivize a load reduction. Specific incentives can also be provided for baseline consumption adjustments. In addition to time-based pricing and rebates, these include interruptible-capacity (ICAP) and emergency demand-response programs that allow system operators to instruct customers to cease consumption on very short notice. Of course, pricing methods can also be combined; for example, TOU pricing can be combined with a separate charge (demand charge) for peak consumption or a PTR (Borenstein, 2005).

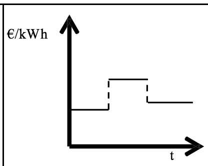
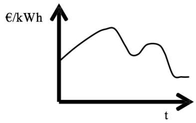
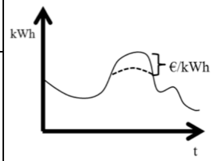
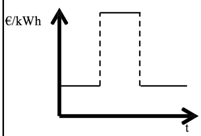
Basic time-based pricing options			Specific incentives for baseline adjustment		
Time- Of-Use (TOU)	Fixed electricity prices for different time blocks within a time		**Peak time rebates (PTR)**	A rebate when electricity is reduced compared to baseline consumption, within certain hours in a year.	
Real- Time-Pricing (RTP)	An hourly rate depending on the day ahead real-time price of		**Interruptible Capacity Program (ICAP), Interruptible load**	A rebate when electricity is reduced below a	
Critica l Peak Pricing (CPP)	High electricity price periods for certain (fixed) days of time within a		**Emergency Demand Response**	Mandatory commitment to reduce load, with penalties if not supplied.	

Table 11.3: Possible time-based pricing options for DER management (David and Lee, 1989; Faruqui and Sergici, 2009; Hakvoort and Koliou, 2014)

Depending on the electricity market design, a distribution system operator (DSO), aggregator, retailer, and/or a third party could provide separate price signals to the end user. With smart grids, ex-ante tariffs can incorporate dynamic prices based on real-time electricity supply and network conditions. Due to the fact that there are minimum trading values for the balancing and other free markets, small users must be bundled or aggregated to simultaneously provide significant tradable amounts of flexibility in those markets (see section 4). Aggregation and load bundling can occur per load type, e.g. EVs can be represented by one entity and home battery systems by another.

11.6 Time-based Tariffs within the Billing Context

Electricity pricing is an important method by which end-user demand response can be incentivized while maintaining voluntary choice. The final electricity bill depends on the respective cost-components and other (policy) objectives associated with the charges allowed under the tariff. This section sequentially describes cost allocation, customer charging and demand response aspects within this context.

11.7 Cost Allocation

Fundamentally, electricity billing is set up to ensure cost recovery of the supplied electricity service. Costs are here seen as the incurred expenses by the retailer or utility to deliver the electricity service, while charges are the fees that are imposed upon the customer for respective use of the electricity service. Cost allocation involves the methods by which electricity supply costs are allocated to electricity customers. If electricity prices are reflective of the costs caused to the system, pricing is considered cost-causality based (Rodríguez Ortega et al., 2008; Sotkiewicz and Vignolo, 2007).

Traditionally, electricity systems were operated by large vertically integrated electricity utilities (combining electricity generation and transport) to with their own electricity billing structures and tariff levels. This model still prevails in many US states and other countries, where electricity is billed by a central public service utility whose regulated tariffs could reflect combined network and electricity supply costs incurred to the final user. Alternatively, in a liberalized electricity sector, the monopolistic components of the electricity value chain (the electricity transport network) are unbundled from the competitive parts (e.g. generation and retail). The general composition of the cost allocation elements in the liberalized electricity market model (mainly prevailing in Europe) is presented in Figure 11.1.

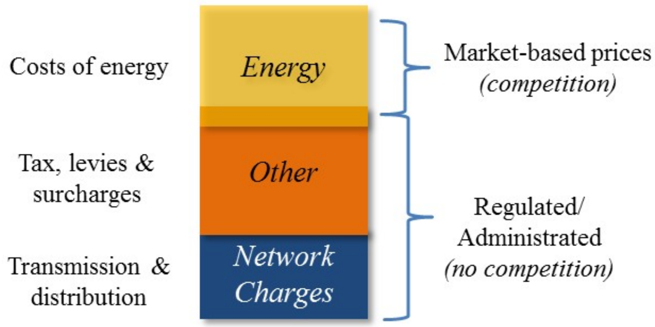


Figure 11.1: Usual breakdown of electricity retail rates in a competitive environment (Eurelectric, 2013)

11.7.1 ***Electricity production***

Traditionally electricity is supplied from large conventional units such as nuclear, coal, and gas power plants that directly feed electricity to high voltage grids. For sustaining reliable electricity supply, at each moment in time and at each network node, generation and demand should be kept in balance. Consequently, depending on the electricity demand in time, generation units are synchronously operated to automatically supply the actual demand of electricity from a *generation-follows-demand perspective*.

However, enabled by smart-grid technologies, increasing levels of demand are now served by stochastic supply from renewable resources and distributed generation. This electricity is not only fed to the high-voltage grids, but also to the low-voltage grids through " prosumption" (Pérez-Arriaga et al., 2013)[1]. Consequently, in future electricity systems the *generation-follows-demand* perspective is increasingly replaced by a *demand-follows-generation* perspective. This transition requires that electricity consumers receive real-time reflective information regarding the electricity prices through dynamic pricing (Pérez-Arriaga et al., 2013).

From an economic perspective, electricity production and consumption can be traded in different ways. In a system with wholesale market competition, for example, at each moment in time the generation units compete to supply the largest share of demand and the market price is set by the cost of the marginal unit (the unit that is supplying each additional kWh demand of electricity). In most countries, wholesale electricity market design has evolved toward the use of short-term marginal costs (normally hour-by-hour, every half hour, or even every five minutes) as the optimal economic signal for energy trading (Reneses and Rodríguez Ortega, 2014). Depending on the available energy mix (the range of types of generation units in a market), the market price is set by the highest priced marginal unit that can supply an additional unit of electricity in the market at a specific moment in time.

In addition to this wholesale market price, which in many cases reflects the real-time price of electricity (for DR purposes), electricity can be traded in liberalized electricity markets in other ways. Retailers and producers can set up bilateral contracts for electricity supply, where only a small part of the electricity demand is traded in real-time. Capacity markets are also utilized for long term procurement of electricity provision by all market parties. Alternatively, where there is no liberalized market, the system operator solely operates its plants centrally and assigns the right unit at the right times for meeting the electricity demand .

11.8 Cost for Electricity Transport

Electricity networks are the transport carriers for supplying electricity from the point of generation to the location of demand. Those networks can be categorized as transmission and distribution networks. Transmission networks are high-voltage (HV) networks that transfer electricity from production plants to substations located near electricity demand. This is distinct from the local networks that distribute low-voltage power to customers.

For both transmission and distribution networks, most of the incurred costs are large investments associated with capital expenditure (CAPEX). Operation and maintenance costs (OPEX) generally represent a much lower portion of total network costs. This distinction is mostly relevant for the remuneration of the network operators, but is of less importance when cost-based tariffs are designed. For this purpose, the total cost is used as input data and allocated to the different network users (consumers, generators and prosumers) according to the costs they cause.

In a traditional electricity system, the distribution system is the final stage in the delivery of electric power; it carries electricity from the transmission system to individual consumers. Emerging cost allocation methods anticipate further development of DG, DR, and prosumption. As technology allows, electricity flows can move not only from high-voltage to low-voltage grids, but also among distribution networks from low-voltage to high-voltage grids if a high level of DG or DR resources become available. These developments suggest that locational price signals might be an advisable regulatory instrument (Reneses and Rodríguez Ortega, 2014), on account of aggregate system pricing diluting location specific signals for triggering demand-side load modification measure

11.9 Other Costs

Besides the main processes of electricity generation and transport, there are other costs related to *policy, metering and customer services, regulation,* and *reconciliation*. Policy costs involved in the electricity supply service include subsidies and taxes for attaining certain policy goals. Examples are subsidies to low-income consumers, tax-incentives, and feed-in-tariffs for renewable electricity generation. These costs, like others, are variable across types of customers and dependent on context.

Costs related to metering and customer services involve expenses in the final stage of electricity supply. These include the cost for call centers and customer assistance, and other costs related to metering equipment and its maintenance. Especially in a liberalized market, there are costs related to the regulation of electricity supply service. Lastly, reconciliation costs are adjustment costs from one year to another. Those costs are ex-ante credited and corrected after ex-post.

11.10 Charging the Customer

The various costs described above make their way into customer charges through the regulated retail tariff, which can be partly politically influenced. Certain customers may be exempt from paying for certain charges for policy reasons.

When designing cost-reflective charges for regulated electric activities, a distinction is often made between CAPEX and OPEX. As noted, there generally is not a direct relationship between CAPEX and fixed charge or OPEX and variable charge (either capacity or energy). For example, when the DSO invests in fixed assets for the purpose of reducing energy losses, these costs would constitute CAPEX for the DSO. However, within tariff design, this cost should be included in the energy charge (€/kWh), since the investment has been made in order to reduce energy losses that relate to energy consumption. Therefore, the distinction between CAPEX and OPEX does not carry over to the fixed and variable parts of the retail price. In reality, strict adherence to fully cost-based pricing requires frequent adjustments to charges and therefore complex tariff design (Eid et al., 2013). Moreover, it could also reduce signal clarity and jeopardize cost recovery over the long term (Reneses and Rodríguez Ortega, 2014).

11.11 Traditional Electricity Billing

Typical billing components on electricity bills are the energy charge (€/kWh), a capacity charge (€/kW), an access charge (a one-time payment), and the customer charge (a yearly or monthly payment). Traditional electricity charging does not further categorize between consumers and prosumers with uniform rate structures. However, in a smart-grid environment where demand participation is fostered, end-user tariffs can incorporate customer categorization, time and location (Picciariello et al., 2015). See Table 11.4 for some examples.

	Basic Tariff Components				
	1. Tariff categories	**2. Billing components**	**3. Time**	**4. Location**	
Component Options	1.Consumer, Generation and Prosumer tariff 2.Consumer and Generation tariff 3.Consumer and Prosumer tariff 4.Solely Consumer tariff	1. Two-fold charge: Energy+ Capacity charge(€/kWh and(€/kW)) 2.Capacity charge (€/kW) 3. Energy charge (€/kWh) 4. Yearly charge (€/year)	1. Real-Time-Pricing (RTP) 2.Time-of-Use (TOU) 3. Flat rate (time independent)	1.Nodal pricing 2. Zonal pricing 3. Uniform pricing (location independent)	***↑↑↑IncreasingComplexity↑↑↑*** ***↓↓↓ReducingCost-causation↓↓↓***

Table 11.4: Tariff components and options for tariff design (Eid et al., 2014)

The application of dynamic prices is different for vertically integrated utilities providing a single (integral) tariff as compared to regulated and private service providers in a liberalized market. The electricity tariff could therefore be divided in the nature of the costs (distribution or retail prices) and these prices could be flat or time-dependent. Otherwise the arrangements could be set for an independent aggregator. The final tariff could reflect full-dynamic prices, semi-dynamic prices, or another pricing arrangements with for example a new actor like an aggregator. If the full dynamic price comprises of an integral tariff in which a single price incorporates both retail and distribution costs. Alternatively, a full dynamic price could be set up by two different prices for both retail and distribution. Within a semi-dynamic price, one part of the price for electricity is can be fixed price, for example like the customer charge in the United States. Other arrangements could be that an aggregator sets up a specific contract for demand response (See Figure 11.2).

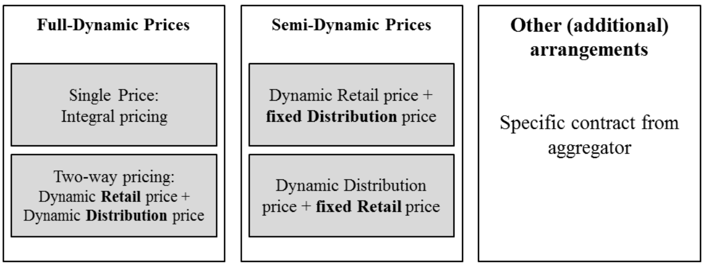


Figure 11.2: Different billing methods to incentivize demand response

11.12 Pricing to Promote Demand Response

For some methods of electricity pricing, including pricing for flexible and reliable demand response, the installation of technical devices is required. For example, with peak-time rebates the baseline consumption level of the customer is needed in order to rebate for the supplied DR. With direct control methods, in-home automation is needed that communicates with the signal from the aggregator for example (or other actor that contracts the flexibility of the end-user). Table 11.5 provides some examples of tariff options and required smart-metering and home adjustments for the customer to be able to supply the DR Service.

	Tools			
Tariff option	***In-home pricing display***	***Real-Time-Metering (Smart Metering)***	***Access to Baseline consumption curve***	***In-home demand control***
Direct Load Control	Optional	Optional (only with additional price based tariff)	Not required	Required
Real-Time-Pricing	Required	Required	Not required	Optional
Critical-Peak-Pricing	Required	Required	Optional	Optional
Peak-Time-Rebates	Required	Required	Required	Optional
Time-of-Use pricing	Optional	Required	Not required	Optional

Table 11.5: Tools required for demand response activation

Certain types of demand flexibility are required in similar ways for the entire year (for example in case of highly congested transmission lines), while other types of flexibility could only require infrequent response during specific events per year (for example, due to extreme weather conditions). From a tariff perspective, this requires a distinction between *permanent* and *transient* price signals. Permanent signals reflecting variations in price related to time, location, size, and direction are mostly used for higher costs categories, such as those related to generation and transmission constraints. This is the case for yearly set TOU rates based on electricity consumption in a frequently congested area or different generation costs during the day. Alternatively, transient signals can be used to reflect variations in distribution costs. Thus, if a zone is congested during only some hours of the year, non-permanent punctual signals such as CPP can be used in that zone.

Time-based and dynamic pricing can furthermore be obligatory or voluntary, with and without opt-in or opt-out methods (Faruqui et al., 2010). In most of the US there is no retail competition; rates for households and small commercial utilities are set by the regulator, who is free to approve a dynamic pricing tariff as a default or option. In the EU, customers would have to actively choose a dynamic-price tariff. Only customers who can lower their bills will voluntarily choose time-based rates. The rate of adoption is a critical point; adoption could be much lower if customers must actively switch to time-based pricing, rather than having it as the default.

11.13 Examples of Demand Response Projects

Demand response is applied in different ways globally, with industrial electricity users being the main providers of system-wide demand-side flexibility. This section provides some examples of DR programs in both the industrial and residential electricity sector.

11.13.1 Industrial demand response

The advantage of having large industrial consumers provide demand response is that their change in consumption patterns significantly affects the electricity system as a whole. Specifically, industry accounts for more than one third of total electricity consumption in Europe, which in turn brings confidence to the predictability of load patterns (EEA, 2012). Aggregation is cost effective and reliable in large volumes due to the tradability of their load flexibility on balancing and reserve markets. In addition to aggregation, large industrial users could also be subject to timed-based or dynamic-pricing from their supplier or TSO in order to incentivize demand response. Below we discuss examples of industrial DR that provide insight into the role of aggregation.

11.13.2 France: energy pool

In France, Energy Pool is an aggregator that started operation in 2008. Its clients are mainly large industries (data centers, hospitals, residential and tertiary buildings, refrigerated warehouses, water cleaning and treatment facilities, and electric vehicles) that are geographically spread across the country. DR consists of around 1000 MW flexible capacity in the form of load reduction. Energy Pool takes charge of optimal decision-making for the industrial user's DR: it identifies flexibility potential, integrates the DR into the normal business processes of its clients, and offers the flexibility in different markets. These markets are the balancing markets (day-ahead and intraday), security reserve markets (long-term contracts and emergency operations), and capacity markets (mid-term or long- term contracts). Energy Pool clients receive specific payments for their participation in load management programs. Energy Pool now operates besides in France also in the UK and Belgium and has contracts with the TSOs in those countries.[28] (EnergyPool, 2014).

11.13.3 United Kingdom: flextricity

Flextricity is an industrial DR aggregator that started operation in 2004 in the United Kingdom. Flextricity provides both generation and load aggregation, meaning that it can incentivize clients for upward and downward load management and eventually trade this

[28] See the website of Energy Pool: https://www.energy-pool.eu/

flexibility in markets. Flextricity's clients are large industrial and commercial customers (more than 500kW) and owners of small hydro and stand-by generators.[29]

Usually there is no cost at all for the consumers to participate in Flexitricity`s aggregation programs, as the company itself installs the communication, metering, and control equipment. The flexibility is supplied to short-term operating reserve (STOR) (generators), which is a service for the provision of additional active power from generation or demand reduction if power fails or demand is higher than expected. Furthermore, DR is used for triad management (comparable with critical peak), which is carefully targeted generation and demand reduction to optimize revenues for the involved businesses in contingency situations. Lastly, this DR is provided for frontline generation and load adjustment on short notice (below 10 seconds f o r 750 kW or more). Furthermore in the industrial and large commercial sectors, energy-intensive users are able to enter TOU or interruptible contracts with suppliers. Similarly, the transmission system operator can contract such large users directly as part of their network balancing activities (Torriti et al., 2010).

11.14 Residential demand response

11.14.1 France: direct load control and Tempo Tariff

An example of rigorous DR is direct load control (DLC) of the customer load by a central actor. Direct load control is mostly applied when the system is in a contingency situation and usually leaves no freedom for the user. An example is provided by the aggregator Voltalis in Brittany, France.4 Customers contracted with Voltalis receive a free device installed in their home, named Bluepod, which reduces heating operations in short time intervals when Voltalis receives a signal from the TSO based on endangered electricity supply sufficiency. In this DR program, customers are automatically enrolled, but can opt-out at any time by pushing a button on the device and using their heater as usual. Users do not receive an additional financial benefit, but observe a reduction of their normal electricity bill (usually 5e10%) due to the interruptions. The advantage of this type of DR is that it requires no additional tariff settlement, and therefore is easy to implement. In France, a combination of CPP and TOU pricing is also applicable for customers that apply for the Tempo Tariff. Electricite de France (EDF), had in 2010 around 350,000 residential customers and more than 100,000 small business customers using the Tempo tariff. Within this tariff scheme, days are distinguished according to price using a color system, together with an indication of whether the hour is currently one of eight off-peak hours. Customers can adjust their consumption either manually or by selecting a program for automatic connection and

[29] See the website of Flextricity: https://www.flexitricity.com/

disconnection of separate water and space-heating circuits. It has been estimated that for the average 1 kW French house, the Tempo tariff brought about a reduction in consumption of 15% on ‘‘white’’ days and 45% on ‘‘red’’ days. On average, customers have saved 10% on their electricity bill (Torriti et al., 2010), which can be significant especially considering harsh winters the reliance of a majority of French households on electric heating.

11.14.2 Sweden: DR for network congestions

Sweden is one of the few countries in Europe with 100% smart meter roll-out (Eurelectric, 2013). A portion of the customers from DSO Sala Heby Energi Eln€at AB, the electricity distribution area that covers the provincial country town Sala and its environs, receive a TOU price for electricity distribution service. Prior to the introduction of the demand-based time-of-use electricity distribution tariff (henceforth referred to as the demand based tariff), all households in the local electricity.distribution area of the utility were charged according to a conventional distribution tariff composed of an annual fixed access charge (SEK/yr.), the rate of which was dependent on fuse size, and a variable distribution charge (SEK/kWh). Alternatively, the demand-based tariff consists of the fixed access charge (SEK/yr.) and a variable distribution charge (SEK/kW) that is calculated based on the average of the five highest hourly meter readings during peak hours. In off-peak hours, electricity distribution is free of charge. In the duration of the program, households experienced an average individual peak demand reduction between 9.3% and 7.5%. When considering the peak in the distribution system, there was an average reduction between 15.6% and 8.4%. The total shift from peak to off-peak hours was between 2.4 and 0.2 h (Bartusch and Alvehag, 2014). Individual households saw a decrease from 14% to 41% in costs over the duration of the project. An analysis of the project attributes some of the savings to prices that were set too low (Bartusch et al., 2011). 4.2.3. The Netherlands: DR pilot for electricity transport and supply In the Netherlands, the DSO Enexis has formed a consortium with an energy retailer (Greenchoice) and a project developer (Heja) to conduct a pilot in an apartment block and a group of semidetached houses in Breda. This project tested dynamic retail, distribution, and local production pricing for household consumers. The retail tariff is based on the day-ahead price variation that is multiplied by a factor in order to make the average price equal to one if the traditional fixed kWh price for electricity from the supplier

would be charged (this fixed price was around 0.2193 €/kWh during the pilot). This results in a retail price fluctuating between 0.06 €/kWh and 0.36 €/kWh each day (see Fig. 11.3). The transport tariff is a dynamic peak-pricing scheme, which is dependent on the daily peak-hours and not solely critical peak hours at event days within a year. The peak pricing scheme for transport applied to consumption taking place above 80% of the consumption load during the daily peak. During days with a high morning peak (such as weekend days), these hours are also charged the peak price (see Fig. 11.4) (Kohlmann et al., 2011).

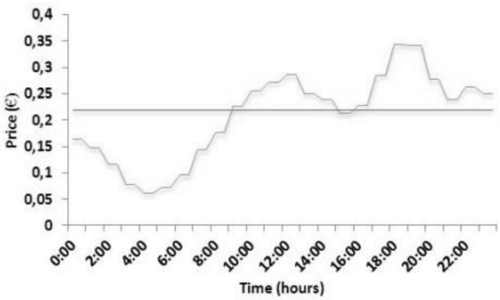


Figure 11.3: Dynamic retail price with the straight line providing the standard electricity price as charged by the electricity supplier (Kohlmann et al., 2011)

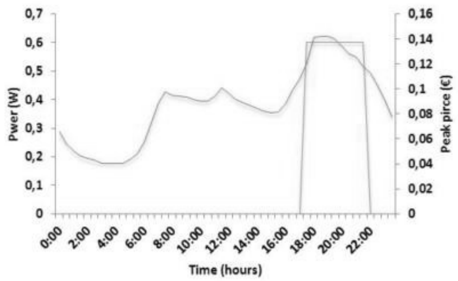


Figure 11.4: Dynamic transport tariff on week day with load curve inWatt and the transport tariff in € (Kohlmann et al., 2011)

In the pilot project, smart appliances react to day-ahead market prices automatically. A smart appliance is fitted with additional ICT components connecting it to the grid. The appliances for this project are the so-called 'wet appliances' (washing machine, dishwasher and tumble dryer).

In the Netherlands (and most other European countries), the DSO is a natural monopoly that should provide non-discriminatory third- party access; it is not allowed to hamper or affect market activities for retailers or other market parties due to the possibility of price discrimination. Dynamic tariffs that vary in both time and place might discriminate customers by increasing price in a geographic area specifically with capacity problems, and not in neighboring areas without capacity problems (Lunde et al. 2015). Therefore legal considerations may limit general application of the tariff settlement used in this pilot project.

11.15 Challenges for Development of DR in Europe

Depending on system characteristics and the extent of electricity sector liberalization, different barriers exist for DR activation. The following sections present the major issues that must be addressed.

11.15.1 Initial technology investments

The installation of smart meters, in-home displays, and other devices for enabling DR is costly. For example, the installation cost of a smart meter in Europe is on average between € 200-250.[30] An important question is who initiates the installation of smart meters—the consumer, the retailer, the aggregator, or the DSO? This common *split incentives* problem is related to the fact that the costs and benefits from flexible demand should be split between the end-user and the enabling actor, in view of creating a viable business case for both (Hakvoort and Koliou, 2014).

For example, if the electricity retailer invests in the smart meter, and the customer wants to change suppliers, this investment by the settled retailer is essentially foregone. If the DSO makes the investment, this constitutes a competitive advantage compared to the retailer because the DSO can use prices to alter consumption

for network purposes. Without any clear business model for investments, no actor will make the first move. It is important that those benefiting from DR, directly or indirectly, pay for the costs (Energy Pool, 2015). Consequently, the value of DR should be distributed along the electricity supply chain, together with incentives for participation for each agent under clearly elaborated business models (Hancher et al., 2013). Therefore, taking into account that environmental benefits of DR are socialized, the cost also could be settled in a socialized manner. And just as it is the case in many markets with priority access for renewables, priority access for demand response in markets could further support its developments (Koliou et al, 2014).

11.15.2 Coordination problems

The *coordination problem* is another issue associated with DR deployment (Hakvoort and Koliou, 2014). At a certain points in time, some actors involved in electricity supply could require the demand to be adjusted downward, while others could actually require upward demand adjustments. This is especially the case in liberalized electricity sectors, where the network and supply functions are unbundled from each other. In Germany, for example, oversupply of wind electricity can result in *low* supply costs, while simultaneous network capacity limits can result in *high* transmission costs. Therefore, trying to incorporate multiple purposes over a time horizon with competing effects is impractical and may lead to unclear economic incentives. How customers respond depends on their price elasticity relative to the particular load modification. Therefore, the assessment of the exact load modification, its time horizon, and the price elasticity for

[30] See the website of the European Commission http://ec.europa.eu/energy/en/topics/markets-and-consumers/smart-grids-and-meters

such response must be taken into account. The coordination issue requires that tariffs ex-ante manage interactions for specific moments in time when opposing signals appear. Furthermore it requires re-consideration of regulation in liberalized electricity markets where the DSO is not allowed to hamper market activity with network tariffs due to non-discriminatory third-party access rules.

In a liberalized sector, in addition to retail and network charges, taxes could further affect price-signal clarity. Alternatively, in a vertically integrated system, the coordination problem is less likely to occur because the utility is able to directly incorporate conflicting effects in a final price. Consequently, it is recommended that policy-makers fix a prioritized set of objectives with the pricing methodology for both electricity supply and transport. For example, signals related to security of supply should take precedence

11.16 Incumbent Issues: Flexibility and Traditional Markets

In Europe, the need for demand flexibility from the residential sector is not critical in many places due to sufficient capacity within the distribution grid and flexibility provision from industrial consumers. However, in the next 15-20 years, when RES are expected to provide a significant part of the electricity production (based on the very ambitious European target of 100% RES in 2050), activating residential flexibility will become increasingly important. As discussed already by Koliou et al. (2014), the rules for balancing, ancillary, and real-time trading should be adjusted to accommodate aggregated load flexibility.

If aggregators are hampered to provide flexibility services, the transition toward a renewable based electricity system becomes a greater challenge. Traditional peaking units in many RES based systems, however, already cope with recovering stranded costs and would be further affected by DR that shifts income to aggregators.

Another important issue is described by Eurelectric with respect to the need for a compensation mechanism that guarantees that electricity suppliers are not penalized for imbalances caused by activities of (independent) aggregators (Eurelectric, 2015). Whenever the aggregator reduces or increases electricity consumption, the deviation is reported in a schedule to the TSO, who will correct the respective balance. Financial compensation should be paid to the balance group for the energy that is consumed or not consumed due to the control of the aggregator. This issue is less problematic if the aggregator is the retailer. The DSO could also take responsibility for DR aggregation. However, within a liberalized electricity sector, the option of DR for commercial purposes is legally not allowed due to required unbundling of the DSO from market functionalities. New market design options allowing for expanded use of locational pricing could incentivize additional resource efficiency.

11.16.1 *Non-sustainable side-effects of DR: shifting peaks and increasing emissions*

A relevant issue with DR tariff schemes is that instead of peak reduction and valley filling, a shifted peak is frequently observed. The low electricity price in valley hours, therefore recreates a transferred peak in time. In France this issue is tackled by differentiating prices for regions in order for DR to smooth loads in desirable ways.

There are are energy-mix dependent consequences of load shifting from peak to off-peak periods. The economic effects of consuming electricity from cheaper production (like coal), might lead to less operation of more expensive units (such as gas fired plans). Depending on the current merit order, sometimes load shifting might induce higher CO_2 emissions as a result of increasing base-load production that is then met by coal-fired units, while reducing peak-load generation that could be met by cleaner, gas-fired units (Conchado et al., 2011; Holland and Mansur, 2008). However, a higher CO_2 emission price may help to mitigate this effect to a large extent.

11.17 Discussion and Policy Recommendations

This paper provided both a theoretical and practice-oriented overview of time-based and dynamic pricing to incentivize demand response for different electricity flexibility needs. In Europe, various DR efforts are visible for industrial and residential users, although the contribution of residential users to DR remains small. Even though in many countries there is currently no urgency for demand response from the residential sector due to overcapacity in the distribution grid, in the next years, renewable energy sources (often distributed) are expected to provide for a significant part of electricity supply. In this situation, adaptive and flexible electricity demand could benefit reliability and cost efficiency at the distribution level as well.

In a liberalized electricity sector, taxes, network charges, and retail charges are separately defined and this can affect price signal clarity for the end-user. We recommend that policy-makers fix a prioritized set of objectives with the pricing methodology for both electricity supply and transport. For example, signals related to security of supply should take precedence. In a vertically integrated system, the coordination problem is less likely because the utility is able to directly incorporate conflicting effects in the final tariff. We recommend designing prices so that "permanent" signals are sent for capital cost categories while "transient" signals are sent for operational distribution and energy costs. For example, when DR is incentivized for handling long-term objectives associated with production and grid capacity constraints, price incentives can be set ex-ante rather than tied to real-time costs (through, for example, a TOU price). For long term planning, effective incorporation of demand response into capacity markets can contribute to minimize the need for generation resources, in turn bringing down overall cost of procurement.

Further research is needed regarding how time-based and dynamic pricing for DR might incorporate signals for other types of flexibility, including distributed generation, storage, and electric vehicle (EV) charging. The interaction of those different sources of flexibility is consequently of importance; for example, contradictions to sustainable objectives might result if usage is priced lower than storage. Lastly, the role of both incumbent and new actors in the electricity sector should be clear when designing DR incentives. Especially in a liberalized electricity sector, the value of DR along the electricity supply chain, the incentives for each agent's participation, and the business models for DR should be clear so that the initial smart-grid investment can be pursued by any the actors involved. Further research is also needed with regard to the use of locational pricing to incentivize additional resource efficiency. Current zonal and country level pricing dilutes locational incentives for demand-side load modification.

In conclusion, we note that demand response is not an objective in itself, but a potentially efficient and sustainable tool for electricity systems with growing needs for flexibility. Is DR economically relevant for systems with spare generation capacity? In that case, what is the best option for introducing DR when conventional units are already coping with cost- recovery problems? These questions remain open and require that policy-makers prioritize objectives with regard to electricity and sustainability in the sector.

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12 Published Paper IV: Market Integration of Local Energy Systems: Is Local Energy Management Compatible with European Regulation for Retail Competition?

*This paper is published in Energy (2016), issue 114, pages 913-922, **by Eid, C.**, Bollinger, A., Koirala, B., Scholten, D., Faccinetti, E., Lilliestam, J., Hakvoort, R.*

12.1 Introduction

In the European Commission, parallel attention is given to the introduction of competition in the electricity sector and the ambitious targets for sustainability. The process of electricity sector liberalization was formally finalized in 2007, inciting competition in the wholesale and retail electricity markets and the unbundling of network activities. The retail competition markets in Europe are largely based on an assumption of centrally managed electricity systems, whereas wholesale markets are increasingly coordinated or merged (European Commission, 2014b). Starting in 2015, all interconnected European power exchanges are coupled, which represents a large step towards the creation of a European internal energy market, the European Energy Union (European Commission, 2015a).

With regard to sustainability, achieving the ambitious 2020 and 2030 European climate targets relies on both the market penetration of large- and small-scale renewables and the deployment of energy efficiency measures (European Commission, 2014a). The recently established Energy Union strategy strongly supports a new market design that would support the integration of higher shares of renewable energy and foster energy efficiency measures contributing to demand moderation (European Commission, 2015b). In Germany and some other countries, supportive feed-in-tariffs have already incentivized the widespread installation of small solar panels in the residential and commercial sector (Anaya and Pollitt, 2015; EPIA, 2014). In 2014, Germany had 38 GW capacity of Solar PV installed, with more than 60% located at low voltage levels (EPIA, 2014). Other examples of rapidly developing residential solar PV segment are found in Belgium, where 1 of 13 households have a PV system, but also in for example Greece and the United Kingdom (EPIA, 2014). Further, Denmark in particular has seen an increased penetration of decentralized combined heat and power (CHP) (Fragaki and Andersen, 2011; Lund and Münster, 2006; Toke and Fragaki, 2008). At the distribution grid level new challenges arise due to the penetration of electric vehicles (EVs) in several countries for the distribution grid, especially in Norway and the Netherlands (ABB, 2014).

To respond to these changes in supply and demand, system operators and suppliers have started to develop new strategies for handling a more decentralized system. Among the more radical solutions is *local energy management (LEM)* – the coordination of decentralized energy supply, storage, transport, conversion and consumption within a given (local) geographical area. Combined with automated control and demand-side management strategies, local energy management, especially with the use of local heating production, holds the promise to significantly increase the efficiency of energy use, reduce carbon emissions and enhance energy independence (Lund et al., 2012; Lund and Münster, 2006; Toke and Fragaki, 2008). Many of these benefits have already been realized in the context of numerous local energy projects initiated worldwide (Jong et al., 2015; UNEP, 2015).

As countries across Europe seek to effectively and efficiently manage the large-scale integration of distributed energy resources, it is important to consider the effect of actor roles and responsibilities for managing the electric flexibility from resources locally in the regulatory context of energy retail competition. Different authors have expressed the difficulties associated with the unbundling of network and market functionalities (Brunekreeft, 2015; Pérez-arriaga, 2013). For example, due to the fact that the DSO is a monopoly party, it is generally not allowed to trade for electric flexibility from end-users.

Yet, because the internal market policy process imposes constraints on how the electricity system can be organised, there may be conflicts between these flexibility management approaches and market regulation. The aim of this paper is to give insight in the compatibility of the organizational structure for flexibility management to fit within the European electricity retail competition context. This is done through analysis of different real-life LEM cases and their organizational structures, comparing them to the traditional organizational structures and possibilities for retail competition and lastly discussing the aspect of scalability of those projects.

We analysed four cases – three Dutch and one German case – drawing both on publicly available material such as (DNV GL, 2015; Energiequelle, 2015; Kohlmann et al., 2011; Mourik, 2014; USEF, 2015) and interviews with involved project partners and managers.

The paper is structured as follows. Section 12.2 describes background information on organizational structures for flexibility management, together with the framework for flexibility management used in this analysis. Section 12.3 describes the method used to analyse the cases. Next, section 12.4 presents the results of the analysis followed by the discussion and conclusions in section 12.5 and 112.6.

12.2 Background

12.2.1 Organizational structures and electricity market integration

The organization and coordination of energy transactions on local electricity distribution level has been explored by numerous scholars for different local energy management concepts. Some analyses focus only on electricity and refer to the terms smart grids, virtual power plants and micro grids (Dielmann and Velden, 2003; DOE, 2006; Hall and Foxon, 2014; Hernandez-Aramburo et al., 2005); and others include thermal and chemical energy carriers with multi-energy carrier systems and refer to the terms energy hubs or smart energy systems (Geidl et al., 2007; Lund et al., 2012). As described in the introduction, in this paper we define local energy management (LEM) as *the coordination of decentralized energy supply, storage, transport, conversion and consumption within a given (local) geographical area*.

This paper aims to present the possibilities for integration of local energy systems in the traditional regulatory context of Europe. Specifically, the focus here is on the aspect of electricity management integration and therefore this paper leaves out the integration of heat or gas supply due to the fact that deserves analysis by itself see Figure 12.1 for a conceptual presentation. In the figure, the aspect of electric flexibility is presented as central. Electric flexibility can be defined *as a power adjustment with a specific size and direction, achieved at a given moment for a given duration from a specific location within the network* (Eid et al., 2016b). Due to the fact that for reliability of supply a constant balance between supply and demand is required, the role of electric flexibility and the management thereof is crucial. This flexibility can be used for multiple purposes, ranging from network congestion management, supply portfolio optimization and renewable integration. In this research, the aspect of flexibility management is analysed from an organizational perspective instead of a technical perspective only. This organizational structure can provide insights in whether a flexibility management method is closely related to the traditional methods of flexibility in the electricity sector in Europe.

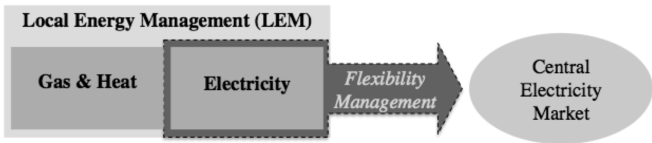

Figure 12.1: The emphasis on electric flexibility management in this work

12.3 Framework for Flexibility Management

When discussing organizational structures, and their impacts on the arrangements of (electricity) markets, the theory of institutional economics becomes of importance. The Williamson framework represents how economic transactions are embedded in layers of formal organization, governance and informal institutions (Williamson, 1998). Künneke proposed a technical counterpart of this framework, which has been further elaborated by other researchers (Correljé et al., 2014; Scholten and Künneke, 2016). This comprehensive framework shows how technical and economic transactions are embedded in their technical and economic environment. For example, for economic transactions, the rules for (spot) market design provides the possibilities for actors to bid in the markets. While differently, from the technical perspective, operational control mechanisms manage the way in which technical transactions take place in real-time. Annex I presents the techno-economic framework. For the analysis in this paper the framework has been adapted to focus on the management of flexibility in electricity systems and provide insight in the most suited design for the European context. The framework presents three layers, a techno-institutional layer, an economic layer and an operational layer. Flexibility management is defined as the application of the four flexibility management variables; *the division of responsibilities (**who**) for specified management of flexibility of appliances (**what**) by specific means (**how**) and for specific time-dependent system purposes (**why**),* and two organizational variables*, the **number of actors** involved and the **nature of transactions**.* Figure 12.2 presents the framework used to analyse the LEM cases in this paper. The next subsections present a description of the different variables.

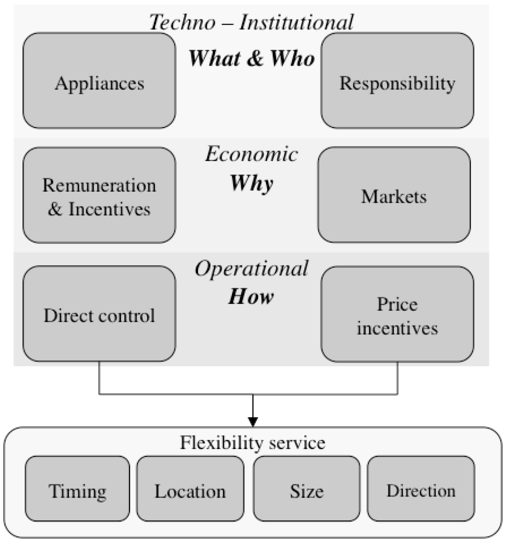

Figure 12.2: Framework for flexibility management in electricity systems

12.3.1 Responsibilities (who)

The actors who take responsibility for the management of flexibility at the low voltage level are most probably to be DSO, retailer, aggregator and/or other actors like the TSO. Depending on which actor takes this responsibility, and its current business model, the flexibility is used for the specific market activities in which this actor is involved and/or the services that this actor provides. For example, the transmission system operator (TSO) is the chief entity responsible for ensuring balance between the electricity supply and demand in the system. This is being done through settlement of various markets, i.e.; ancillary service market and balancing markets (Eid et al., 2016b). In those markets, large generators and industrial customers are eligible to bid their offers for the provision of upward or downward flexibility. At the distribution network level, there are no markets for such flexibility currently (outside of pilot projects). Still the different actors might have specific interests involved with the use of flexibility; the retailer could use the flexibility for portfolio optimization, while the distribution system operator (DSO) could use the flexibility to reduce congestions for example as it is done in Sweden (Bartusch and Alvehag, 2014). The level of engagement in the activities for flexibility management by DSOs however remains dependent on the regulated remuneration for the activation of flexibility. In Europe, most DSOs are subject to incentive regulation, which means that their expenses should reduce with an efficiency factor each year. However, the procurement of flexibility through smart grid solutions can increase the operational expenses in time which can counteract the tendency of the DSO to embark on this route (Eid et al., 2016c).

12.3.2 Appliances (what)

An actor can perform responsibility over the management of flexibility of a specific (set of) appliance(s). The appliances appointed could be specific, in-home appliances like washing machines, electrical heaters or the EV, solar PV units and CHP units. Differently, the flexibility could be provided by the entire household consumption (for example with the provision of a time-based tariff for the entire household consumption). Each appliance has specific technical abilities providing specific flexibility services (Eid et al., 2016b).

12.3.3 Signals (how)

There are different ways to activate flexibility. The most common signals for flexibility activation are direct control, semi-direct control and indirect signals (also named price signals). **Direct control** provides direct access from a central actor (like an aggregator) to control the operation of contracted devices. Direct control provides secure flexibility within a specific time and location for the procuring actor and provide ease to the end-user due to the fact that the end-user does not manually have to activate its units. Differently, **semi-direct control** refers to the ability of end-users to predefine time bands for which the devices are providing flexibility, and after which the operations of the devices are automatically adjusted**.** Semi-direct control is often used for a price signal (explained hereafter), in order to automate the activation of devices at low-price time periods.

Differently, **indirect signals** refer to price-based signals. The flexibility obtained from those types of arrangements refers to "changes in electric usage by end-use customers from normal consumption patterns in response to changes in the price of electricity over time" (DOE, 2006). There are multiple time-based pricing options available ranging from real-time pricing (RTP), critical-peak pricing (CPP), time-of-use pricing (TOU), and peak-time rebates (PTR) (Newsham and Bowker, 2010). The price options differentiate from each other mostly based on the price variability that they represent in time. Real-time prices change very frequently (from around every 15 minutes to hourly basis) while time-of-use prices can change on a time basis of 4 hours. Different from direct control, indirect control leaves freedom to end-users to participate in the flexibility service provision. Therefore those signals do not provide security on the expected capacity of flexibility.

12.3.4 Markets (why)

Markets provide the organizational environment of economic trading. Markets provide the organizational environment of economic trading. For flexibility management, markets can exist for specific timeframes before real-time (for example ancillary service and balancing service markets) and also include the location dependency of that specific market (for markets for congestion management are organized from a multi-node perspective).

Flexibility management in the electricity system requires different types of flexibility services, defined by different timeframes before real-time (ancillary services are traded very close to real-time versus capacity markets which are much longer from real-time). Furthermore, beside the time-dependency, the electricity system also has a location dependent need for flexibility in case of network congestions. Therefore, balancing markets are typically centrally organized while markets for congestion management are organized form a multi-node perspective of the system. The organization of markets in which actors are allowed to trade provides a financial incentive for flexibility management in the system. The already existing markets for flexibility are those in managed by the TSO and partly by the market operator.

12.3.5 Number of actors involved and nature of transactions

Beside the diverse flexibility design variables presented here, furthermore organizational variables are of interest, which related to the way in which the market is organized. These variables are the number of actors involved and the nature of their transactions (Scholten, 2013). The nature of transactions can be horizontal, hybrid or hierarchical. When a single actor is managing the flexibility, it naturally presents a hierarchical nature of transactions between end-user and the central deciding actor. However, when two or more actors are involved with flexibility management, the nature of the transactions can be horizontal or hybrid. With a horizontal organization, all the actors have equal influence on the flexibility management. When there are hybrid transactions, it can be the case that the transactions are not entirely horizontally arranged but one specific actor is appointed to manage the flexibility on behalf of other actors.

12.4 Method

In this work, four cases are analysed using Table 12.1, which is based on the framework presented earlier in this paper in Figure 12.1. For each case, the four flexibility management variables are described and the two organizational variables. The information from these cases comes from publicly available material and from interviews with the project managers involved.

Variables	Options	Base case:[31] **Flexibility management in electricity sectors in Europe)**
Who is responsible?	DSO, retailer, aggregator and/or other actor	At high voltage level: TSO *At low voltage level: No specific responsibility for flex management*
What appliances are managed?	E.g.: CHP, PV, EV, customer appliances and/or consumption	At high voltage level: large generators and customers *At low voltage: None*
How is flexibility activated?	Price incentives or direct control	At high voltage level: Through direct control & price incentives *At low voltage: Normally no flexibility activated, sometimes if retailer/DSO provides a (price) incentive* (Eid et al., 2016d)
Why is this flexibility activated?	Balancing, day-ahead, ancillary services and/or for local market, etc.	Existing TSO markets: e.g. ancillary services, balancing market, congestions markets etc. At low voltage: no specific market available
Number of actors involved	1 or more	Single buyer (TSO), many sellers of flexibility *At low voltage: Not specified due to absence of market*
Nature of **transactions**	Hierarchical, Hybrid or Horizontal	Horizontal *At low voltage: Not specified due to absence of market*

Table 12.1: Flexibility management variables used in this paper

Together, the insights in the separate the flexibility management variables can provide an indication of how well the organizational approach suits to the European regulatory context and the possibilities for upscaling of this approach. The situation as it is currently the case in most European countries is presented in the last column of Table 12.1.

The level in which the cases provide possibilities to adhere to retail competition context and allow upscaling, relates to the way in which (1) multiple retailers can trade in such system, (2) the roles that the traditional actors like the DSO take within the case and (3) the possibilities for upscaling. The possibilities for upscaling is related to the nature of the transactions; the more hierarchical nature of transactions, the less complex it is to scale the presented approach up due to the fact that the transactions are managed on a singular method. Differently, generally the more actors involved, the more competition this case

[31] A more comprehensive overview of the use of flexibility in traditional markets can be found in (Eid et al., 2016b)

represents (less monopolistic) and therefore would better suit the retail competition model in Europe.

Due to the fact that this work is aimed to show what type of organizational structure would result it most suited one to the European context, this paper focuses mainly on the specified variables and organizational aspects for flexibility management. Or course, within each case, there are many more indicators that provide insight in the technical and economic performance of the system. For example, the cost of electricity within various time-scales for each case, the power of the installations for each case and symbolic mathematical model for each approach. Even though this information is interesting from a techno-economic view, this would not support the aim of this work of discussing about the suitability to the European context. Therefore the focus remains on the arrangement of flexibility management and the organizational structure involved.

12.5 Results

The following sections present the different organizational models for flexibility management. The names (e.g. Multi-Objective Optimization and Dynamic Pricing) have been chosen to illuminate the central flexibility management concepts used in examples. The cases have been shortly in order to remain focused on the most important aspects for the organizational structures for flexibility management. Please find the indicated references for detailed information on this aspect.

12.6 Case 1: Multi-Objective Optimization

Power Matching City (PMC) is a project located in Hoogkerk, a city within the Netherlands (see Figure 12.3). There are three actors involved for the management of flexibility: the consumer, the DSO and the retailer (flexibility variable **who**). The project includes 40 households with installations of Solar PV, EVs, heat pumps, micro CHP and a Powermatcher device (flexibility variable **what**). This Powermatcher manages the operations of the appliances and interacts with the local market, taking into account the actor preferences. In this project, direct control is applied for the heat pump and the micro CHP (i.e. controlling electricity production). The operations of the washing machine can be pre-defined and therefore semi-direct control is provided to those appliances (flexibility variable **how**). All other household consumption units are not being controlled, nor any price-incentive is given for general consumption. Each of three involved actors bids (in an automated manner) in the market through which a “balance price” is given at each moment in time (flexibility variable **why**). This local market takes into account the day-ahead spot market price, balancing market price, local transformer loading and the consumer preference for electricity consumption.

12.6.1 Nature of the transactions and number of actors involved

In this case, the retailer, DSO and consumer play an important role in the transactions for flexibility. The IT system acts as a real-time trading platform for local transactions between the different trading agents (DSO, retailer and consumer) which can bid within the local market, providing a local balance price. Consequently, due to the fact that there is not a central actor making the decisions, the nature of the transactions in this case are horizontal.

12.6.2 Comparison to base case

Firstly, the DSO, retailer and consumer take up a different role within this case compared to the traditional retail competition context. In the daily operations of within the multi-objective optimization project, the retailer, DSO and end-user have been permitted to procure flexibility for individual economic objectives locally. However, in the current retail competition context in Europe, markets are not located at the distribution level but only at the transmission level. Traditionally the DSO, retailer and end-users do not have this role and permission to trade flexibility at the local level.

Secondly, within PMC an issue exist for the coordination of flexibility between actors. In PMC the different interests of the actors regarding flexibility management have been arbitrary divided; all agents received a certain measure of flexibility. Experience showed that at certain moments in time conflicts could arise in the procurement of flexibility. Often, for instance, one party needs all available flexibility but could only use its own part from the resident, or two actors would need the flexibility at the same time. Therefore, in PMC, the energy supplier took the role to decide about who will receive what type of flexibility (DNV GL, 2015). However, in a retail competition context as in Europe, where end-users should be able to choose their supplier, this case can even become more complex due to the fact that coordination is required between multiple retailers, the DSO and the consumer.

12.6.3 Possibilities for upscaling

Therefore, in order to make this case possible within the retail competition model in Europe, a readjustment is needed regarding roles and responsibilities of actors together with a method for the set-up of local markets, which allows for multiple retailers to be integrated. Next to the definition of those two important steps, furthermore a settled method is required to locally divide the flexibility between different agents when this is procured simultaneously, also referred to as the coordination problem (Hakvoort and Koliou, 2014). Appointing an actor to take care of the distribution of flexibility could support this, however it should be taken into account that this actor might be biased towards specific market objectives (instead of efficient network utilization) when involved in market activities. Therefore an important aspect is the definition of fairness (DNV GL, 2015) from a social perspective for an unbiased division of flexibility that supports overall objectives of the sector. Lastly, in order to motivate the DSO to procure flexibility, adjustments in the regulated income of DSOs are required.

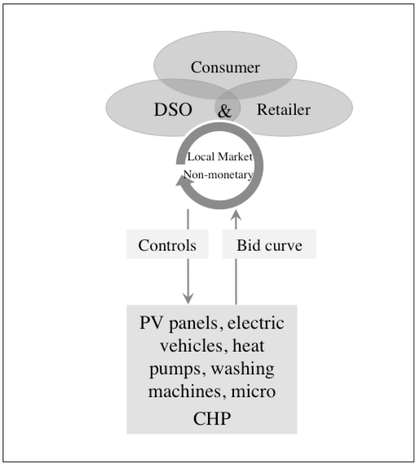

Figure 12.3: Organization of flexibility management in Multi-Objective Optimization project "Power Matching City"

12.7 Case 2: Dynamic Pricing

Within The Netherlands, the project "Your Energy Moment" is a pilot within an apartment block and a group of semi-detached houses in the city Breda (see Figure 12.4). Within this project, a time-dependent two-hour varying tariff (€/kWh) is presented to the consumer via an in-home energy display (flexibility variable **how**). This final tariff includes both a price component of the retailer and of the DSO (flexibility variable **who**). Each of the households owns a PV unit and net-metering with the time dependent electricity tariff takes place for remunerating the PV production. The retail tariff is based on the price variation in the day-ahead market while the time-dependent transport tariff is a peak-pricing scheme, which is related to the daily network peak-hours (Kohlmann et al., 2011) (flexibility variable **why**).

The time-dependent tariff stimulates customers to shift their total household electricity consumption in time. However, to support this load shifting, the customers are equipped with a smart appliance, that, if programmed by the consumer, will automatically turn on the 'wet appliances', namely the washing machine, dishwasher and tumble dryer (flexibility variable **what**) at the cheapest moments in time.

12.7.1 Nature of transactions and number of actors involved

In this case, the nature of the transactions in the market is horizontal due to the fact that the DSO and retailer both have the possibility to present their tariff to the end-user. However, if compared to the multi-objective optimization case, this case represents a less horizontal market arrangement due to the one-directional price signal provided to the end-user by the DSO and retailer. The consumer is not involved in the bidding process but merely exposed to this signal. Therefore in this project the nature of the transactions is horizontal, but in a reduced form than in the Multi-Objective Optimization case.

12.7.2 Comparison to base case

In the Netherlands and most other European countries, the DSO is obligated to provide non-discriminatory third party access with flat pricing schemes. Traditional regulation could hamper the time based pricing from the DSO due to the risks for market power, especially when at some moments the distribution price is higher than the retail electricity price. The price signal given by the DSO in this case however might lead to discrimination in time and location for the use of electricity. The regulation for DSO price settlement is therefore an important conflict with the retail competition model for DSO.

12.7.3 Possibilities for upscaling

An important adjustment firstly is the allowance for DSO to provide time-based tariffs, and the provision of regulatory incentives for DSOs to do so. If the DSO is not being remunerated to reduce investment expenses by slightly increasing operational costs for the procurement of flexibility, the DSO will remain uninterested in the development towards price-based activation of flexibility.

Secondly, guidelines are required for the price signals given by the retailer and DSO, which will be then forwarded to the consumer through a settled formula. In order to fit within the retail competition context, multiple retailers should be able to provide their specific price signal, which then is combined with the local distribution price. The possibilities for upscaling in this case are less difficult than the Multi-Objective Optimization case, due to the fact that only the price signal the activator of flexibility is, and not a simultaneous bidding process between multiple actors, as it was the case with the Power Matching City case.

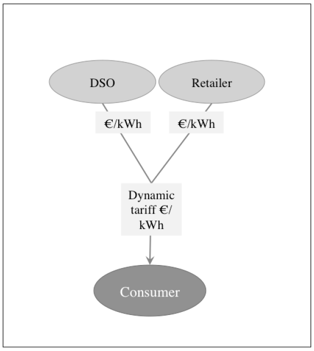

Figure 12.4: Organization of flexibility management in Dynamic Pricing project "Your Energy Moment"

12.8 Case 3: Local Aggregator

The Local Aggregator is a case referring to the project "Energy Frontrunners" (Energie Koplopers in Dutch) in the municipality Heerhugowaard, in the Netherlands (See Figure12.5)[32]. The applied flexibility management method is described Universal Smart Energy Framework (USEF)[33]. In this project 240 households have a "device installed that is remotely controlled by which direct control is applied on appliances (flexibility variable **how**) by the local aggregator (flexibility variable **who**). In this project, the aggregator is the Dutch retailer Essent and controls the operation of heat pump, electric boiler, fuel cells and PV curtailment (flexibility variable **what**). Besides being the aggregator, Essent is also the balance responsible party (BRP), in charge of trading flexibility on the national balancing markets (**why**). However, in this pilot project, the trading transactions are simulated and do not take place in reality.

The DSO buys flexibility from the aggregator in order to reduce the solar peak from the PV panels and reduce the evening peak consumption in the local distribution network. Eventually, at the end of the month, the (simulated) revenue that has been created from trading activities in the balancing market and from the network optimization is divided among the participating households.

12.8.1 Nature of transactions and number of actors involved

The aggregator takes a central role in this case, and is trading on behalf of the balance responsible party and the DSO. Due to this central role of the aggregator, the nature of the transactions can be seen as a hybrid due to the fact that a single actor is responsible for operations but takes into account the requests of the DSO and BRP.

12.8.2 Comparison to base case

In the pilot project, all the households had the freedom to choose their own retailer, independent whether this retailer was the one responsible for the aggregation and balance responsibility. However, in a retail competition environment, it would be unbeneficial for retailers that have supply contracts with customers when an independent aggregator is able to make changes in their supply programs to the end-users (Eurelectric, 2015, 2014). This would reduce their revenues due to the penalties that need to be paid when unexpected changes in overall end-user consumption take place.

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[32] See for more information https://www.energiekoplopers.nl/contact/

[33] See for more information: www.usef.info

Secondly, next to the issue of balance responsibility, furthermore also in this case the role of the DSO is different from that in the traditional liberalized electricity sector in Europe. As described in the previous cases, the DSO as natural monopoly is generally not incentivized nor allowed to procure flexibility.

12.8.3 Possibilities for upscaling

Due to the monopoly role of the aggregator, firstly a clear definition of its role and degree of freedom with regard to the management of flexibility is required. For this aggregator, which could be a regulated party, it should be clearly defined what transactions that are allowed with the DSO and BRP while safeguarding customer desires with the direct control on appliances.

Secondly, an important adjustment is also here regarding the allowance and incentives for DSO to procured flexibility. If the DSO is not being remunerated to reduce investment expenses of the grid by slightly increasing operational costs for the procurement of flexibility, the DSO will remain uninterested in the development towards price-based activation of flexibility.

Lastly, in order enable the possibility to have retail choice for customers, specific compensation mechanisms should be set up for retailers that are affect due to the adjustments in their customers' consumption by the independent aggregator.

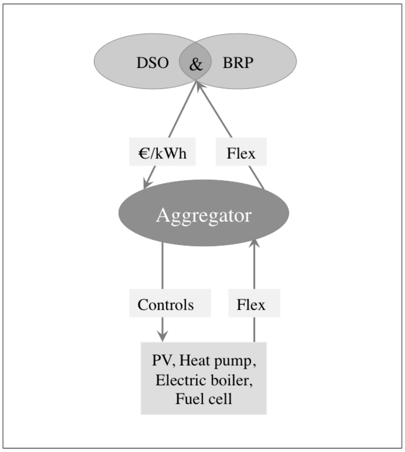

Figure12.5: Organization of flexibility management the Local Aggregator project "Energy Frontrunners" adapted from (USEF, 2015)

12.9 Case 4: Local Integrated Utility

The village of Feldheim (Germany) represents an example of a co-operation between private households, the municipality and project developers for the management of decentralized renewable energy system (see Figure 12.6) (Energiequelle, 2015). This system is managed by a cooperative, which is both the retailer and owner of the electricity network manager of flexibility (flexibility variable **who**). The project includes 37 households, two businesses, two local government entities as well as three agricultural enterprises. The cooperative is uses direct control (variable **how**) to activate flexibility from a lithium-ion battery storage, biomass plant, wind power plant and solar PV farm (variable **what**). The net-production from the PV, wind and biomass is being sold back to the grid and is remunerated via a feed-in tariff. The flexibility from the battery storage is being sold for the provision of flexibility services for frequency control and the operation of the DER are controlled in order to abide to network constraints (Energiequelle, 2015) (flexibility variable **why**).

12.9.1 Nature of transactions and number of actors involved

The cooperative as a single monopolistic actor takes all decisions regarding the operations of the DER locally. Consequently, the nature of the transactions that take place in the Feldheim project present a hierarchical form. There is no involvement of a DSO or retailer due to the fact that the cooperative is the owner of the local network and responsible for the reliability of supply.

12.9.2 Comparison to base case

The locally owned and operated electricity system presented in the integrated utility could be seen as conflicting with liberalization rules due to the fact that network operator is not unbundled from the electricity supply. Local customers in theory are then not eligible to choose their supplier. However, due to the fact that the local customers are mostly also shareholders in the cooperative, this retail choice does not affect their interest for another retailer. However, some customers still decided to choose another retailer administratively (probably due to the fact that they are not part of the cooperative) while the cooperative is still responsible for ensuring overall reliability of electricity supply.

A risk of this development is that if all customers choose to be administratively contracted with another supplier than the local cooperative, this would lead to cost recovery problems for the local supplier and eventually reduced reliability of supply. The end-users however, in this project are shareholders within the cooperative and therefore this is an incentive for being contracted with the local cooperative. In long term, if many cooperatives would pop-up (without local shareholders) there is a risk that all users are willing to be contracted only with the cheapest retailer available in the country.

12.9.3 Possibilities for upscaling

This project inherently does not provide possibilities for retail choice, due to the fact that the Local Integrated Utility is both network owner and supplier of retail services. This goes against the regulation for unbundling of the network operations (the monopolistic activities) from supply activities in the retail competition context. Where, in the retail competition context it is assumed that retail choice will foster efficiency in the sector; differently, with a

Local Integrated Utility with local shareholders the drive for efficiency results directly from the community both owning the cooperation and being end-users of its services. This case therefore inherently provides an alternative to the retail competition through self-regulation, than possibilities for retail competition.

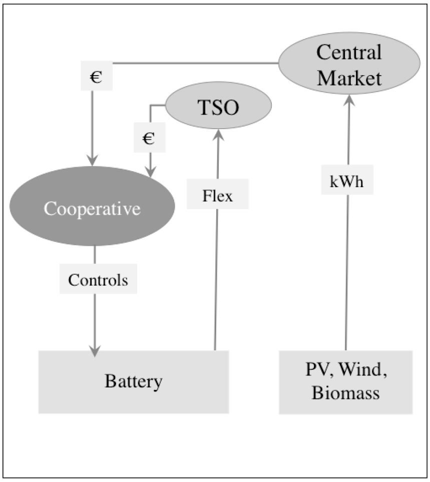

Figure12.6: Organization flexibility management the Local Integrated Utility project "Feldheim"

12.10 Discussion

The presented cases show a range of different approaches for flexibility management in LEM projects. The results are summarized in Table 12.2. The next sections summarize the findings and conclude on the most suitable approach for scalability in the European context.

	Case 1	Case 2	Case 3	Case 4
Case	**Multi-Objective Optimization**	**Dynamic Pricing**	**Local Aggregator**	**Local Integrated Utility**
Project Name	Power Matching City	Your Energy Moment	Energy Frontrunners	Feldheim
Who is responsible for flexibility management?	DSO, Retailer and Customer preference	DSO and Retailer	Aggregator	Co-operative
What is managed?	PV panels, electric vehicles, heat pumps, washing machines, micro CHP	PV panels, smart washing machines and heat pumps	PV panels, heat pump operation, electric boiler and fuel cell	Wind, Solar PV, Battery, and Biomass plant
How are the appliances managed?	**Direct control**	**Dynamic pricing**	**Direct Control**	**Direct Control**
Why (for what purpose is flexibility used)	Reduction of network peaks & supply optimization in time-steps of 5 minutes	Reduction network peak & day-ahead market optimization with time-steps of 2 hours	Reduction network peaks & balancing services in time-steps of 5 minutes	Reduction network peaks & frequency control in time-steps of 15 minutes
Number of actors involved	3	2	1	1
Nature of transactions	Horizontal	Horizontal	Hybrid	Hierarchical

Table 12.2: Overview of flexibility management and organizational structures in the LEM case studies

12.10.1 The possibilities for retail choice

An important value for the retail competition model is that customers have freedom to choose their retailer. For the different cases, there are different levels of complexity in ensuring retail choice to customers. The easiest method to provide retail choice is the Local Aggregator model (case 3), due to the fact that the household electricity consumption is not controlled by the aggregator but only specific appliances. When the aggregator changes the consumption levels of end-users with diverse retailers, a compensation mechanism is required to make up for the changes in the balancing responsibility program.

Differently, the dynamic pricing and multi-objective optimization cases represents more technically complex projects due to the fact that the retailers and DSOs are actively involved (in an automated manner) with the management of flexibility. In those projects, guidelines are required to make sure that multiple retailers are allowed to access a part of the flexibility of the end-users by means of direct control (Case 1) or present their individual (standardized) pricing schemes to the customer (case 2).

With the Local Integrated Utility case, the cooperation is both owner of the local network and retailer of electricity. End-users in this case are customers of this local retailer and both shareholders in the local cooperation. In order to make sure a similar project would adhere to the requirements for retail competition, it might be at risk that some end-users will chose to become customers other retailers instead of the local one if the local electricity price is higher than another retailer available. This could be adjusted by making sure (just as in the Feldheim case) that a specific amount of end-users are contracted locally and others are free to choose. However, this does not fully signify retail competition.

12.10.2 Possibilities for upscaling in Europe

The number of actors involved in the management of flexibility ranges between one and three in the different cases. In the Multi-Objective Optimization project the transactions between the DSO, retailer and consumer were of horizontal nature. Due to the fact that the transactions between those actors take place in real-time, the Multi-Objective Optimization represents a project with the highest level of operational efficiency, however also highest complexity and related transaction costs. Especially when integrating diverse retailers within this project (Verzijlbergh et al., 2014). In the Dynamic Pricing project, both the DSO and Retailer are involved with flexibility management by means of a time-based price signal. This represents horizontal nature of transactions, but in a lower scale as that one of the Multi-Objective-Optimization due to the fact that the consumer is not involved but merely exposed to a price signal. In the Local Aggregator project, a single actor is responsible on behalf of the DSO and balance responsible party, representing hybrid nature of transactions. Lastly in the Integrated Utility Model one central actor was responsible for flexibility management, representing a very hierarchical nature of transactions. Figure 12.7 represents conceptually the cases and the nature of the transactions between the different actors.

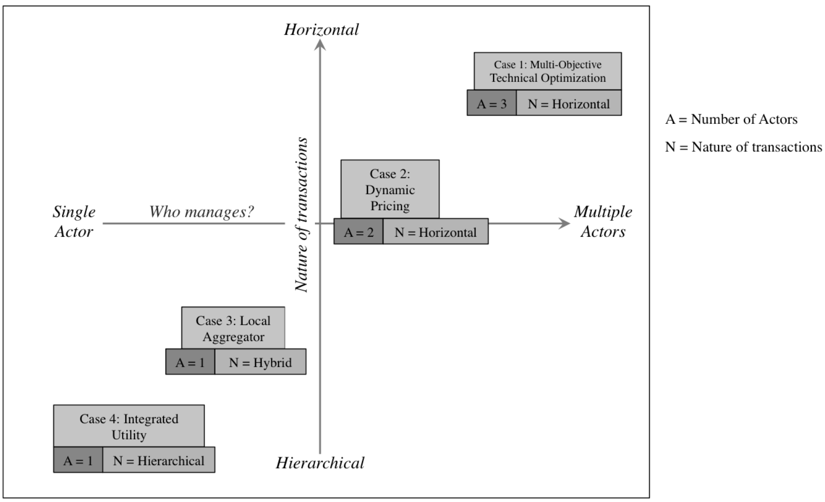

Figure 12.7: Conceptual presentation of cases and nature of transactions

In order to discuss the scale in which the cases would suit to the European retail competition context and provides possibilities for upscaling, two points are of interests. Firstly, in what degree are multiple retailers able to retail their electricity to end-users simultaneously? And secondly, what is the degree of complexity involved with upscaling this methodology for further development in Europe?

All cases except for the Integrated Utility theoretically provide the possibility for retail competition. However, the more horizontal the nature of the transactions and the number if actors involved, the more technically complex the system becomes for retail competition. This is mostly the case for the Multi-Objective Optimization approach in which an iterative process of demand bidding is used for the management of flexibility. Such algorithm for an iterative grid capacity market may solve congestion in an economically efficient way, but its implementation requires frequent exchange of information between the DSO agent, retailer agents and consumer agent increasing complexity and transaction costs of this specific approach to adhere to retail competition.

The dynamic pricing model provides a more simplified method for multiple retailers to compete for flexibility by formalizing the computation for the final dynamic tariff to the end-user, before real-time. Therefore this is a less complex method than the Multi-Objective Optimization approach and probably more feasible for upscaling.

The aggregator model is another approach suitable for upscaling. Due to the fact that the transactions are managed by a single aggregator that is operating on behalf of the DSO and BRP, the integration of multiple-retailers is simple due to the fact that end-users can choose any supplier. However, principles need to be set for the compensation between the BRP and retailers for the imbalances that have been created by the aggregator. Furthermore, in order to make sure that the market activities do not overtake network activities (and the other way around), the aggregator should be a regulated party or this activity could be fulfilled by an actor that is already regulated; the DSO.

The needs for flexibility provision and management have everything to do with the purpose for which this is used in the system. In the presented projects, trading of flexibility has been used to manage network peaks (in all projects), to align with the day-ahead market price variations (in the Dynamic Pricing Model and Technical Optimization Model) and to trade flexibility in balancing markets (Local Aggregator and Integrated Utility Model).

When trading for flexibility takes place within already existing markets, the involved traders receive monetary value for the flexibility procured. However, in traditional retail competition markets no market model exists for trading of distribution network capacity. Therefore, as discussed earlier in the paper, such type of trading cannot be made monetary at this moment without adjusted regulations and market design especially for the DSO within cases 1-3. Due to the fact that the rational for the DSO to procure flexibility in Europe is not logical due to the method by which most DSOs are remunerated. Incentive based regulations which are used mostly in Europe motivate DSOs to reduce operational expenses (OPEX) and/or capital expenses (CAPEX) in time with an efficiency factor. Generally, the costs related to flexibility trading would be considered OPEX on which efficiency measures apply. Therefore, it would be for the DSO not beneficial to procure flexibility due to the fact that this would increase the operational expenses. By allowing the costs related to the procurement of flexibility (CAPEX and OPEX) to remain outside the regulatory benchmark, policy makers could support the DSO to utilize flexibility of end-users. An important issue with flexibility management for DSOs is that due to their monopoly position at their geographic area of service, the price of flexible demand cannot be competitively set. Therefore, such trading, without sufficient transparency on pricing might lead to too high benefits for the DSO.

To conclude, due to the feasibility of those projects and possibilities to include retail competition, the Local Aggregator and the Dynamic Pricing project would be most suited for upscaling in the European context.

Beside the organizational structures presented in this work, also other organizational structures could be designed including aspects from different cases. An example is a Local Aggregator utilizing an ex-ante defined time-based price from the retailer after which the aggregator takes into account DSO requests for direct control at moments of network congestions. This approach decreases the need for frequent compensation mechanisms between a BRP and the retailers but still provides incentives for efficient use of flexibility taking into account network limits.

12.11 Conclusions

This paper presented an analysis of four organizational models for flexibility management. We study these models using cases from the Netherlands and Germany. The case studies have been categorized as Multi-Objective Optimization, Dynamic Pricing, Local Aggregator and Local Integrated Utility. The analysis utilized four flexibility management variables (who, what, how and why), and two organizational variables (the number of actors involved and the nature of transactions).

The different approaches impose new roles on traditional actors, especially on the distribution system operator (DSO) and the retailer. Traditionally, in the retail competition model, the activities of the DSO are limited in order to ensure a level playing field for all market participants. According to their current investment rationale, which is based on incentive based schemes, DSOs would not be incentivized to increase operational expenses in order to procure flexibility. Therefore to change the DSO’s investment rationale from mainly that of upgrading network capacity towards one in which the DSO focuses on the efficient use of network capacity through flexibility management requires that the regulated income of the DSOs includes the increased operational expenses for procurement of flexibility.

The cases show that the nature of transactions for flexibility management can vary from more horizontal arrangements to more hierarchical arrangements (with a local coordinating actor like a utility or aggregator). Horizontal arrangements are inherently more complex. On the other hand hierarchical structures provide greater feasibility for upscaling and also the possibility to incorporate multiple retailers, given that it the central actor is not a Local Integrated Utility. Our analysis shows that the Dynamic Pricing and Local Aggregator approaches would be better suited to fit the retail competition context in Europe. The issue that remains is the aspect of financial compensation between retailers and the balance responsible party (as shown in the Local Aggregator case). Besides the organizational structures presented in this work, other approaches for organizational structures could also be designed. An example is a combination of the Local Aggregator and Dynamic Pricing approach in which each retailer provides an ex-ante defined time-based price for the sale of their electricity after which a Local Aggregator or the DSO itself takes responsibility for flexibility management to avoid network congestions.

This work provides insight into the impact of organizational structures on the roles of the actors and on the feasibility large-scale deployment of these arrangements in the European regulatory context. An important next step would be a quantitative analysis of the costs of activating local flexibility taking into account diverse organizational approaches. A comparison of activating the flexibility locally versus centrally in the system along with an analyses of the impact of appointing the DSO as a central coordinating actor for flexibility management on transaction costs and economic efficiency would provide interesting insights. Lastly, the authors recommend that future work should be conducted on the economic viability of various socio-institutional and technical alternatives for self-regulation in local energy systems.

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15 List of Publications

Peer reviewed journal papers:

1. **Eid, C**., Bollinger, A., Koirala, B., Scholten, D., Faccinetti, E., Lilliestam, J., Hakvoort, R. (2016). Market integration of local energy systems: Is local energy management compatible with European regulation for retail competition? Energy, 114, 913-922.

2. Facchinetti, E., **Eid, C**., Bollinger, A., Sulzer, S., (2016). Business model innovation for Local Energy Management: a perspective from Swiss utilities. Frontiers in Energy Research, 4, 31.

3. **Eid, C**., Codani, P., Perez, Y., Reneses, J., Hakvoort, R. (2016). Managing electric flexibility from Distributed Energy Resources: A review for incentives, aggregation and market design. Renewable and Sustainable Energy Reviews, 64, 237-247.

4. **Eid, C**., Koliou, E., Valles, M., Reneses, J., Hakvoort, R., (2016). Time-based pricing and electricity demand response: Existing barriers and next steps. Utilities Policy, 40, 15-25.

5. **Eid, C.**, Reneses Guillén, J., Frías Marín, P., & Hakvoort, R. (2014). The economic effect of electricity net-metering with solar PV: Consequences for network cost recovery, cross subsidies and policy objectives. Energy Policy, 75, 244–254.

6. 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.

7. **Eid, C**., Grosveld, J., Hakvoort, R. (2016). Assessing the costs of electric flexibility from distributed energy resources: A case from The Netherlands. Sustainable Energy Technologies Assessment. (Under Review)

Conference Proceedings, Bookchapters, Reports and Working Papers:

1. **Eid, C.**, Hakvoort, R. & de Jong, M. (2017) The political economy of smart grids in the political economy of clean energy transitions. Oxford University Press.

2. **Eid, C.**, Hakvoort, R. & de Jong, M. (2016) Global trends in the political economy of smart grids: A tailored perspective on ‘smart’ for grids in transition. 2016/22. Helsinki: United Nations University UNU-WIDER.

3. Deane, J.P., Hartel, R., **Eid, C.**, Pollier, K. (2015). Quantifying the "merit-order" effect in European electricity markets. Rapid Response Energy Brief, Insight_E project in call from European Commission.

4. **Eid, C**., Codani, P., Perez, Y., Hakvoort, R. (2015). Aggregation of Demand Side flexibility in a Smart Grid: A review for European Market Design. In 12th International Conference on the European Energy Market. Lisbon: IEEE. Nominated for best student paper award.

5. **Eid, C.** (2015). Demand Response in Europe's Electricity Sector: Market barriers and outstanding issues. IFRI. Paris.

6. Koliou, E., **Eid, C.,** & Hakvoort, R. A. (2013). 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. Stockholm: IEEE.

7. **Eid, C.** (2012). Solar Photovoltaics Policy in Europe Losing Sight of what is Right? Current developments and Lessons Learned for Policymakers and Industry. IFRI. Paris.

16 Curriculum Vitae

Cherrelle Eid was born on March 16, 1988. She grew up in Rotterdam, in the Netherlands. In 2010 Cherrelle obtained her Bachelor of Science in Technology, Policy and Management at Delft University of Technology (Delft, the Netherlands).

After her Bachelor's degree, Cherrelle went on to complete an Erasmus Mundus Joint Master's 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 Master's in the Electric Power Industry (2011) and one year at the University of Paris-Sud XI (Paris, France) where she received a Master's in Numerical Economics and Network Industries (2012).

In September 2012 she began an Erasmus Mundus Joint Doctorate in Sustainable Energy Technologies and Strategies (SETS) at Delft University of Technology. As part of the SETS program, she spent 10 months at Comillas Pontificial University (Madrid, Spain) and 6 months at the University of Paris-Sud XI (Paris, France).

During her PhD research, Cherrelle collaborated with numerous researchers from academia and policy institutes like the United Nations and IFRI (Institut Français des Relations Internationales, Paris). Cherrelle published four journal papers, one book chapter, co-authored multiple other publications and presented her work at international conferences.

17 Annex I: Data and Results for Chapters 6 and 7

17.1 Electricity and Gas Prices

	In EUR/kWh incl tax	In EUR/kWh excl tax
NL GAS price	0.078	0.038
EU GAS	0.062	0.047
NL electricity	0.16	0.12
EU electricity	0.2	0.14

EUR/USD rate:	0.92059
USD/EUR rate	1.0863

Source date 27.03.2017

17.2 Monthly Average Prices in the Dutch Day-ahead Market

APX Endex (1 April 2016 - 31 March 2017)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
€/MWh	50.77	43.06	34.52	25.32	27.19	32.59	33.08	28.36	32.85	38	42.85	43.49
€/kWh	0.051	0.043	0.035	0.025	0.027	0.033	0.033	0.028	0.033	0.033	0.043	0.044

17.3 Tesla Battery Cost

	Investment cost ($/kWh)	Tesla S-car Size	Total battery price ($)
Tesla battery	$200	60 kWh	12,000.00

Tesla battery cost see: https://electrek.co/2016/02/26/tesla-vertically-integrated/

17.4 Technology Cost Assumptions

	Startup time (in Hrs)	System Capital Cost ($/kWh) [34]	Battery Capital Costs ($/kWh)	O&M ($/kW/year)	Variable O&M ($/kWh)	Lifespan (Years)	Mechanic Efficiency	Cycles in lifetime
Battery Li-ion	0	305	1000	5	0.007	10	0.8	5000
Battery NaS	0	305	415	5	0.007	12	0.78	3500
Flywheel	0	1277	100	18	0.001	15	0.825	
CAES	0.25	1000	3	7	0.003	30	0.55	
EV Storage	0	620	0	0	0	30	0.93	5000
Gas turbine	0.17	2250	0	11.7	0.011	30	0.3	
Microturbine	0.02	3400	0	11.7	0.011	30	0.25	
Micro CHP (Fuel Cell)	3	5750	0	5.5	0.035	30	0.465	
Power to heat	0	2000	150	14	0.035	15	3.5	
RES curtailment	0	620	0	0	0	30	0	
Demand management	0	620	0	0	0	30	1	

The costs for the different technologies in the above table are taken from the Department of Energy "*National Assessment of Energy Storage for Grid Balancing and Arbitrage Phase II Volume 2: Cost and Performance Characterization*" (DOE, 2013); *The Environmental Protection Agency, " Catolog of CHP Technologies - U. S. Environmental Protection Agency Combined Heat and Power Partnership*" (Environmental Protection Agency, 2015) and the National Renewable Energy Laboratory (NREL, 2010) "*Cost and performance assumptions for modeling electricity generation technologies". Furthermore information is taken from "Flexibility Options in Electricity Systems"* (Ecofys, 2014).

[34] Including balance of plant cost (BOP) and power conditioning system (PCS) cost. BOP and PCS include the cost of the facilities needed beside the flexibility unit itself.

17.5 Revenues Balancing Market

Based on Dutch energy prices including tax

	Technology investment cost (€/kW)	*15 mins*	*Expected techno-logy lifespan in yrs*	*Yearly revenues (Upward Flex)*	*Yearly revenues (downward flex)*	*Total revenues*	*Break even in nr of Years*	*Return on investment*	*Return on investment per year*
↑↓	Battery Li-ion	3047	10	x	x	x	x	x	x
↑↓	Battery NaS	1458	12	x	x	x	x	x	x
↑↓	Flywheel	1659	15	607	23	630	3	7,446	496
↑↓	CAES	n/a	30	x	x	x	x	x	x
↑↓	EV Storage	674	30	x	x	x	x	x	x
↑	Gas turbine	n/a	30	x	x	x	x	x	x
↑	Microturbine	3693	30	17	x	17	221	-3,193	-106
↑	Micro CHP (Fuel Cell)	n/a	30	x	x	x	x	x	x
↓	Power to heat	2580	15	x	x	x	x	x	x
↑	RES curtailment	674	30	x	x	x	x	x	x
↑↓	Demand management	674	30	1107	397	1504	0.45	32,540	1,085

Revenues in balancing markets based on Dutch energy prices excluding tax

	Technology investment cost (€/kW)	*15 mins*	*Expected technology lifespan in yrs*	*Yearly revenues (Upward Flex)*	*Yearly revenues (downward flex)*	*Total revenues*	*Break even in nr of Years*	*Return on investment*	*Return on investment per year*
↑↓	Battery Li-ion	3047	10	x	x	x	x	x	x
↑↓	Battery NaS	1458	12	x	x	x	x	x	x
↑↓	Flywheel	1659	15	770	336	1106	1	9,899	660
↑↓	CAES	n/a	30	x	x	x	x	x	x
↑↓	EV Storage	674	30	x	x	x	x	x	x
↑	Gas turbine	n/a	30	x	x	x	x	x	x
↑	Microturbine	3693	30	198	x	198	19	2,245	75
↑	Micro CHP (Fuel Cell)	n/a	30	x	x	x	x	x	x
↓	Power to heat	2580	15	x	x	x	x	x	x
↑	RES curtailment	674	30	x	x	x	x	x	x
↑↓	Demand management	674	30	1107	397	1504	0	32,540	1,085

Revenues in balancing markets based on EU-28 average price including tax

	Technology NPV (€/kW)	***15 min***	***Expected techno-logy lifespan in yrs***	***yearly revenues (Upward Flex)***	***yearly revenues (downward flex)***	***Total revenues***	***Break even in nr of Years***	***Return on investment***	***Return on Investment per year***
↑↓	Battery Li-ion	1005	10	x	x	x	x	x	x
↑↓	Battery NaS	649	12	x	x	x	x	x	x
↑↓	Flywheel	1742	15	590	6	596	3	7,127	475
↑↓	CAES	671	30	x	x	x	x	x	x
↑↓	EV Storage	343	30	x	x	x	x	x	x
↑	Gas turbine	n/a	30	x	x	x	x	x	x
↑	Microturbine	2078	30	93	x	93	22	702	23
↑	Micro CHP (Fuel Cell)	n.a.	30	x	x	x	x	x	x
↓	Power to heat	2490	15	x	x	x	x	x	x
↑	RES curtailment	343	30	x	x	x	x	x	x
↑↓	Demand management	343	30	1107	1107	2214	0	33,042	1,101

Revenues in balancing markets based on EU-28 average price excluding tax

	Technology NPV (€/kW)	***15 min***	***Expected technology lifespan in yrs***	***yearly revenues (Upward Flex)***	***yearly revenues (downward flex)***	***Total revenues***	***Break even in nr of Years***	***Return on investment***	***Return on Investment per year***
↑↓	Battery Li-ion	1005	10	x	x	x	x	x	x
↑↓	Battery NaS	649	12	x	x	x	x	x	x
↑↓	Flywheel	1742	15	590	44	634	3	7,231	482
↑↓	CAES	671	x	x	x	x	x	x	x
↑↓	EV Storage	343	30	x	x	x	x	x	x
↑	Gas turbine	n/a	30	x	x	x	x	x	x
↑	Microturbine	2078	30	93	x	93	22	702	23
↑	Micro CHP (Fuel Cell)	n.a.	30	x	x	x	x	x	x
↓	Power to heat	2490	15	x	x	x	x	x	x
↑	RES curtailment	343	30	x	x	x	x	x	x
↑↓	Demand management	343	30	1107	1107	2214	0	33,042	1,101

TOWARDS THE DESIGN OF FLEXIBILITY MANAGEMENT IN SMART GRIDS

A TECHNO-INSTITUTIONAL PERSPECTIVE

CHERRELLE EID

The European policy focus on smart grids implies their development as an indispensable part of the future power system. However, the definition of a smart grid is broad and vague, and the actual implementation of a smart grid can differ significantly, depending on the stakeholders involved.

This work aims to inform policy makers, the electricity industry and researchers about stakeholder interests and the technical complexities involved by presenting smart grids via a techno-institutional framework. This framework takes account of the technical nature of the electricity transport and supply service as well as the institutional nature of electricity markets, stakeholder perspectives and sector regulation. In addition, this work presents potential revenues resulting from flexibility management in smart grids and proposes a way forward for smart grids and flexibility management in Europe.

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