DG ENERGY
FRAMEWORK SERVICE CONTRACT
SRD MOVE/ENER/SRD.1/2012-409-LOT 3-COWI
COWI CONSORTIUM
COWI BELGIUM
AV. DE TERVUEREN 13-B
B-1040 BRUSSELS
BELGIUM
TEL +32 2 511 2383
FAX +32 2 511 3881
WWW.COWI.COM

EUROPEAN COMMISSION
DG ENERGY

IMPACT ASSESSMENT STUDY ON DOWNSTREAM FLEXIBILITY, PRICE FLEXIBILITY, DEMAND RESPONSE & SMART METERING

FINAL REPORT

REQUEST NUMBER: ENER/B3/2015-641

JULY 2016

EUROPEAN COMMISSION
DG ENERGY

IMPACT ASSESSMENT STUDY ON DOWNSTREAM FLEXIBILITY, PRICE FLEXIBILITY, DEMAND RESPONSE & SMART METERING

FINAL REPORT

REQUEST NUMBER: ENER/B3/2015-641

JULY 2016

CONTENTS

APPENDICES

Executive summary

This is the final report of the study: *Impact assessment study on downstream flexibility, price flexibility, demand response & smart metering* under contract SRD MOVE/ENER/SRD.1/2012-409-LOT 3-COWI.The study has prepared by COWI in cooperation with AF Mercados EMI, ECOFYS, THEMA and VITO.

Background and objective

Traditionally the development of EU's electricity markets has centred on the role of the supply side in meeting Europe's needs. The combination of the increased generation by variable RES and the technological advances brought about by the advent of smart metering have shifted the attention to the role that the demand side can play in making electricity wholesale and retail markets function better and achieve more efficient grid management.

The objective of the study has been to assess the current situation with regard to demand response, project how the business as usual situation is likely to develop and assess alternative policy options in response to identified problems.

In simple terms, there are two main types of demand side response[1]:

› Price-based (or implicit) demand response refers to a situation when consumers can choose to be exposed to time-varying electricity prices or time varying network grid tariffs that reflect the value and cost of electricity and/or transportation in different time periods, and react to such signals.

› Incentive-based (or explicit) demand response refers to a situation where consumers or agents working on their behalf (demand aggregators) are allowed to participate and provide demand side resources on the wholesale energy, reserves/balancing, and/or capacity markets.

[1] EURELECTRIC, *Everything you always wanted to know about demand response*, 2015.

Problems and objectives

The EU's electricity sector needs more flexibility to enable it to accommodate the significant growth in variable/inflexible RES that will account for an increasing share of the electricity generation. Failure to create flexibility will lead to significant curtailment of RES and/or increased generation and network costs. Demand response is the most immediately available way of increasing the flexibility and may actually be the cheapest flexibility option compared with other options including flexible generation, storage and better interconnection. It is therefore a key element in EU's energy policy to increase flexibility.

Though there have been steps to promote demand response, for example through third energy package of 2009, there are still barriers for utilising more of the demand response potential. The objective of the study is to assess these barriers and the impacts of alternative options to overcome the barriers.

Market failures that may impede demand response include weak competition as a key element. Though the liberalisation is in progress, there are still links between the generator and the suppliers. In many countries, there are one or very few dominant suppliers who may have limited interest in facilitating demand response.

The assessment of the current situation has identified many barriers for demand response to overcome. They can be grouped into the following categories:

- Consumer's ability to react (meters, tariff structure and knowledge)
- Market design and regulation (access rules and incentives)

To overcome these barriers, the following policy options have been defined:

- Option 1: Demand response is promoted by legislation that gives all EU consumers a right to demand access to smart meters and dynamic pricing contracts.

- Option 2: Demand response is promoted by legislation as under Option 1 and standardised EU market rules are established for demand response service providers.

- Option 3: As Option 2 but where the demand response service provider has the right to offer its services without compensation to the retailer/BRP.

The study has assessed the impacts of these alternative policy options and of the business as usual situation.

Assessment of impacts

The assessment of the impacts of the alternative policy options is very complex given that many factors are in play. Key factors include future technological developments in home automation and storage, developments on the energy markets, as well as the situation in each Member State regarding the details of electricity market design and regulation.

The approach to the assessment of the policy options has included the following elements:

- Assessment of a theoretical potential for demand response
- Assessment of the current level of demand response
- Assessment of how each option is likely to increase the share of the theoretical potential being realised
- Estimation of the costs and benefits of the options

The theoretical potential is based on an assessment of the nature of the electricity use by industrial, commercial and residential consumers and represents the maximum potential for shifting demand. The theoretical potential reflects the potential shift in demand (load shifting, peak shaving and valley filing). However, it is assumed that total demand will be unchanged.

Through a review of studies and data on the current volume of demand response, an estimate of the current level of EU wide demand response has been made, which is used as the basis for the BAU path up to 2030. Table 1 presents the key assumptions on the theoretical demand response potential and how much is activated under the BAU measures in terms of capacity and in percentage of peak load.

Table 1 Theoretical potentials, peak load and BAU estimates (GW)

Capacities	2016	2020	2030
Peak load (current and estimated)	486	500	568
Total maximum theoretical DR potential	110	120	160
In % of peak load	22%	24%	28%
BAU	21	23	34
In % of peak load	4.3%	4.6%	6.0%

Source: Own calculations based on Gils (2014) and Entso-E

Based on the experience in the Member States with demand response, the impacts of the options on the volume of demand response they will activate is estimated.

Key elements include:

- Price based demand response (Option 1)[2]: This assumes a limited additional uptake of meters and dynamic price contracts. The proportion of consumers with smart meters rises from BAU values of 71% in 2020 and 74% in 2030 to 81% in 2030 under Option 1. A parallel increase in the take-up of dynamic price contracts leads to an overall increase in the demand response for all consumers.

[2] Option 2 and 3 include the same price based demand response as Option 1

- Incentive based demand response (Option 2 and 3): Options 2 and 3 are about allowing incentive based demand response by defining standardised rules for how demand response can enter the different energy, capacity/balancing markets and grid management services.

    - Wholesale markets:
        - ensure that demand participates at a level playing field with generation through BRP
        - reduce the market resolution (i.e. from hourly to 15 minutes or less)
        - move market closure closer to the operation hour
        - extend the number of bidding possibilities to take account of the wider range of heterogeneity on the demand-side
    - Balancing markets:
        - Reduce minimum bid volumes to allow for smaller loads to participate or allow aggregation of smaller, dispersed volumes
        - Adjust bid duration, recovery time, response time, etc. to fit the demand side
        - Set up standard processes and settlement between aggregators and suppliers
        - Introduce shorter-term procurement reducing the risks for grid users
        - Allow for procurement on all voltage levels

- The interference between the retailer (BRP) and the aggregator is handled in one of these manners:
    - The suppliers (with BRP) integrate aggregated DR as part of their service offering and the suppler and aggregator operate in a single portfolio
    - Aggregator and BRP are not operating in the same portfolio. Their activities are thus clearly split, either through standard contract procedures and agreements or by the aggregator taking on a second balance responsibility for activated loads

    - The aggregator operates independently from balancing responsibility without any compensation to the BRP

The assessment considers each of the models for compensation and while in the long term integration of BRP and aggregator would provide coherent incentives within the EU target model, it requires that there is no vertical market integration between generators and suppliers to provide a level playing field between the demand and generation side. Hence, the second model is likely to be more feasible, and this is also recommended by ACER. The third option does not ensure a level playing field nor fair competition rules between the supplier and the aggregator since the responsibilities and awards are not equally divided between the parties.

The results of the assessments are presented in Table 2.

Table 2 Estimated demand response of the alternative policy options (GW)

Capacities		**2016**	**2020**	**2030**
	Price based	5.8	6.4	15.4
	Incentive based	15.6	16.3	19.0
BAU		**21.4**	**22.7**	**34.4**
	Price based	5.8	6.9	17.9
	Incentive based	15.6	16.3	19.0
Option 1		**21.4**	**23.3**	**36.8**
	Price based	5.8	6.9	17.9
	Incentive based	15.6	20.3	34.6
Option 2		**21.4**	**27.2**	**52.4**
	Price based	5.8	6.9	17.9
	Incentive based	15.6	21.4	39.3
Option 3		**21.4**	**28.4**	**57.1**

These estimated levels are subject to large uncertainty given all the factors that influence the activation of demand response. The overall level of 50 GW of demand response is in line with reviewed studies and expert estimates.

Factors that could influence the above estimates are:

- Smart appliances/home automation: a more accelerated development might increase demand response

- Electricity price development: The above estimates are not based on specific modelling of the markets. They are based on the level of experiences seen in the most advanced markets. The price differences between peak and off peak loads are the main incentive for demand response. Greater RES capacity combined with existing power plants becoming obsolete etc. could increase the price differentials and thereby increase the market value and eventual activation of demand response.

- Price development for balancing and capacity services: This has not been modelled, but is likely to rise with an increasing share of intermittent RES. However, a more efficient market design and a standardisation of rules between MS may limit price developments for these services.

The price development of electricity and balancing/ capacity services may also be a stronger driver than the policy options themselves, meaning the volume of demand response of option 3 may be reached by the policies in option 2 in the case of high prices. Option 3 gives the best business opportunity for aggregators, everything else equal. But aggregation can just as well be profitable in policy option 2 if the value of flexibility increases over time.

The cost and benefits of the options have been estimated. The costs are defined as the activation costs for the different consumption elements (e.g. industrial cooling, residential heating etc.). The costs increases with level of demand response being activated. The benefits are determined as the reduced need for back-up capacity. BA yearly load curve for EU28 is computed and the effects of demand response in smoothing the curve is estimated. Then, the effects on the need for peak load capacity has been estimated. Additionally, the effects on the transmission and distribution network – lower capacity - are added to the benefits of reduced peak generation.

The results of the assessment of the costs and benefits are summarised below.

Table 3 Costs and benefits of policy options for 2030

MEUR/y	Costs	Benefits			Net benefit
		Network	Generation	Total	
BAU	82	980	3,517	4,497	4,415
Option 1	303	1,068	3,772	4,840	4,537
Option 2	322	1,383	4,588	5,971	5,649
Option 3	328	1,444	4,736	6,180	5,852

Using the approach described above the additional net benefits of the alternative policy options compared to BAU amounts to about 120 MEUR/y for Option 1, 230 MEUR/y for Option 2 and around 1,440 MEUR/y for Option 3. The net benefit refers to the estimated savings in generation and network capacity minus the costs of meters and activation.

The follow-on or indirect effects depend on how the savings are distributed among the different actors. Some will go to the lower electricity bills for the consumers and some will go to the aggregators. Lower electricity costs will increase welfare for the residential consumers and increase competitiveness for industrial and commercial consumers.

The distributional impacts cannot be estimated in quantitative terms. It will depend on the specific market situations and the market prices that will be established.

Qualitatively, the following "winners" and "losers" can be identified.

Table 4 Distributional effects of policy options by actor

Actor	Option 1	Option 2	Option 3
Generators	Will lose profit on intra marginal generation at peak load	Will lose profit on intra marginal generation at peak load	Will lose profit on intra marginal generation at peak load
Network operators	Reduced need for investment – no change in profits	Reduced need for investment – no change in profits	Reduced need for investment – no change in profits
Suppliers	Potentially, reduced risks as consumers reduce peak load demand where wholesale prices are high and exceeding the retail prices.	As Option 1 plus effect from more even wholesale prices. Both gains and losses.	As Option 2 though possible larger effects on wholesale prices.

Actor	Option 1	Option 2	Option 3
BRP	No change	No change	Will lose on extra balancing costs (increased financial risk)
Aggregators	No change	Increased business opportunities	Increased business opportunities (more than in option 2)
Consumers	Reduced electricity bill	Reduced electricity bill (more than in option 1)	Reduced electricity bill

For aggregators, the scope of opportunities depends on the details of the compensation rules. There will be a better business case without compensation, but the additional profit will come at a loss to BRPs and potentially higher system costs to be covered by the consumers.

Overall, the main "loser" will be the generators that earn high intra marginal profits on the generation at peak times where the prices are high. The winners will be the consumers that see lower electricity costs. The aggregators and the consumers will share the part of the gain that derives from the incentive based demand response. The effect on suppliers are difficult to estimate. There could be gains from reduced wholesale prices at peak demand. On the other hand, if wholesale prices off peak increase, then this could result in a loss. Overall, the effect would depend on the specific contracts between suppliers and consumers and the precise changes in wholesale prices.

Overall comparison of options

The impacts of the alternative policy options are summarised in the table concerning each of the following assessment criteria.

- Effectiveness (how much additional demand response is achieved)
- Efficiency (cost-benefit of each option)
- Coherence (how the options fit with EU policies in particular the EU objectives)
- Distributional effects (assessment of how the different stakeholders will be affected)

This is a simple qualitative scoring based on the assessment above.

Table 5 Costs and benefits of policy options

	Effectiveness	Efficiency	Coherence
Option 1	+	+	++
Option 2	++	+++	+++
Option 3	+++	+	-

Note: + means positive effect of increasing magnitude

Option 3 is achieving a higher demand response than Option 1 and 2 and therefore more effective. The low scoring of Option 3 with regard to efficiency is due to risk of the introducing inefficiencies in the balancing markets. Coherence is highest for

Option 2 as it allows both price and incentive based demand response to be realised while adhering the EU policy objectives for internal markets and fair competition.

1 Introduction

This report has been prepared by COWI A/S in cooperation with AF Mercados EMI, ECOFYS, THEMA and VITO under the existing COWI Service Framework Contract with DG ENER covering Technical Assistance Activities (Ref. SRD MOVE/ENER/SRD.1/2012-409-LOT 3-COWI) and in response to the Terms of Reference included under Work Order ENER/A4/516/2014.

1.1 Purpose

The objective of the study is to identify and assess the impact of potential policies aimed at fully exploiting the demand response potential in the EU. It covers industrial, commercial and residential sectors in order to improve the economic efficiency of electricity consumption in the context of increased intermittent generation and new energy technologies. The final outputs of this study may provide supporting evidence and analysis for legislative and non-legislative proposals to be adopted by the European Commission in late 2016.

1.2 Structure

The first section below, Section 2, provides a detailed background on demand response, including a description of what it involves, as well as discussion of its increased importance, its potential to address current challenges as well pre-requisites for how such potential can be turned into reality. The next section, Section 3, presents the legal and policy context and how attempts to promote demand response have fared both within the EU and internationally, in particular in the US. This section also includes a detailed analysis of the main barriers faced and how EU intervention could potentially address such barriers. Section 4, outlines a range of possible policy objectives as well as detailed policy options.

Section 5 presents the quantification of the policy options. It includes a review of data on the existing level of demand response for price and incentive based demand response. Then, the mechanism for the policy options to increase demand response is discussed. It is following by an estimate of the level of demand response for each option and for 2020 and 2030. Finally, the costs and benefits of the policy options are estimated.

Section 6 includes a comparison of the policy options. The assessment includes effectiveness, efficiency, coherence and an assessment of the distributional impacts.

2 Demand response

2.1 Importance and implications of demand response

Traditionally the development of EU's electricity market has centred on the role of the supply side – that is the role of electricity generation – in meeting Europe's needs in a sustainable way at an affordable price. Recent developments, such as the technological advances brought about by the advent of smart metering as well as the need for demand flexibility to counter greater supply side inflexibility caused by increased variable RES on the system, have shifted the attention to the role which the demand side – namely customers and their agents – can play in making electricity wholesale and retail markets function better.

In this regard, in 2013, the European Commission noted that the '*potential of the demand side response at the Union scale is enormous: peak demand could be reduced by 60 GW, approximately 10 % of EU's peak demand*'[3]. In short, such potential, if tapped, can lead to a number of direct benefits including lower electricity costs and greater system reliability and greater indirect benefits such as lower CO_2 emissions through changes to consumption patterns and greater penetration of RES. However, despite this considerable potential, the EU's electricity markets remain primarily driven by the supply-side of the sector. The reasons for this are explored in detail in the remainder of this section.

2.1.1 Definition of demand response?

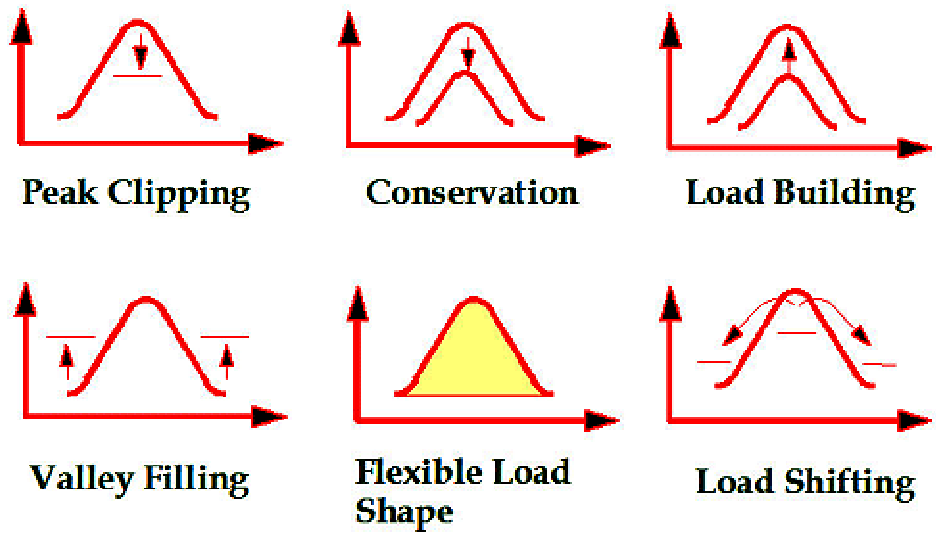
Demand side response, or demand response, refers to a number of actions which customers, or agents acting on their behalf, can do to change their use of demand side resources at strategic or peak times. The US Federal Energy Regulatory Commission, FERC, defines demand response as "*Changes in electric usage by demand-side resources from their normal consumption patterns in response to*

[3] European Commission, Communication, *Delivering the internal electricity market and making the most of public intervention*. November 2013.

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 jeopardised[4]".

While these actions typically involve either shifting electricity use from peak times to off peak times, or simply using less at peak times, demand response can also mean increasing electricity use. The diagram below present the different effects which demand response incentives can have.

Figure 2-1 Different effects demand response (RAP, 2013)



As can be seen, while demand response in the vast majority of cases decreases overall peak demand[5] and tends in most cases to decrease overall consumption, it can nonetheless actually encourage greater use at off peak times (for example valley filling and load building). Therefore, demand response is as much about optimising the use of electricity system (e.g. matching demand with generation and vice versa) as it is not only about reducing energy usage.

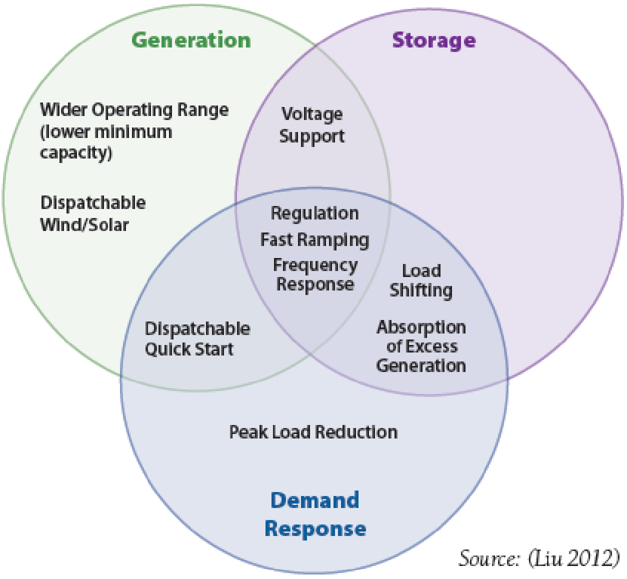
There are a number of ways in which demand can respond. These include installing an alternative energy service as a back-up for electricity, shifting demand in time due to temperature inertia, storage possibilities (battery or heat) or simply shifting to another time due to higher elastic demand preferences.

In terms of the service it provides to the system, beyond simple changes to peak demand and changes to consumption, demand response can also substitute for services which are now provided by generation plant and compete with existing (e.g. pumped storage) and nascent storage technologies. Therefore, demand response is more complex than simply reducing peak demand response.

---

[4] RAP/Synapse, *Demand Response as a Power System Resource*. 2013.
[5] If poorly designed a demand response programme can simply shift the peak to another time, thereby resulting in the same level of investment as before. However, this appears to be quite rare.

Figure 2-2 Types of demand response services (RAP, 2013)



For example, and in concrete terms, demand response can provide services aimed at increasing market efficiency as well as short and long term system reliability. It can do so as a potential substitute (i.e. it can remove the need for peak generation) and/or complement to generation and storage technologies (it can foster the development of storage technologies). These services or benefits are further explored in the next sub section.

In simple terms, there are two main types of demand side response[6]:

› Price-based (or implicit) demand response refers to a situation when consumers can and choose to be exposed to time-varying electricity prices or time varying network grid tariffs that reflect the value and cost of electricity and/or transportation in different time periods and react to such signals.

› Incentive-based (or explicit) demand response goes beyond price-based demand response by allowing consumers or agents working on their behalf to participate and provide demand side resources wholesale energy, reserves/balancing markets and capacity markets.

While both response methods have the same aims and share a number of attributes, they differ in a number of ways.

In simple terms, price-based demand response typically refers to retail (domestic, commercial and industrial) customers responding to time-differentiated retail tariffs set by suppliers. Price-based demand response can encapsulate a number of different types of tariff structures from simple and static (e.g. set in advance) peak/off 'time of use' (TOU) tariffs to dynamic tariffs (Real Time pricing, RTP, and

---

[6] EURELECTRIC, *Everything you always wanted to know about demand response*, 2015.

Critical Peak Pricing, CPP) which vary with underlying wholesale market prices. Their point of commonality is that, while the level of price exposure differs considerably from one tariff type to another, in neither case is the customer active in the wholesale market, hence the reference to 'retail markets'. The demand response is seen as being 'implicit' as the network and market operators do not know in advance how a customer will react to price signals.

Incentive-based demand response, on the other hand, involves direct or 'explicit' demand side participation – either by the customer or by an intermediary (such as by an aggregator) – in the wholesale market. In contrast to price based demand response, by involving direct participation of demand in the wholesale market (or through an aggregator), incentive-based demand response not only affects the energy market through dispatch decisions and hence wholesale market formation, it can also be used to optimise system operation through the provision by the demand side of reserves and balancing. In short, if reliable, the network and market operators can treat demand as negative generation.

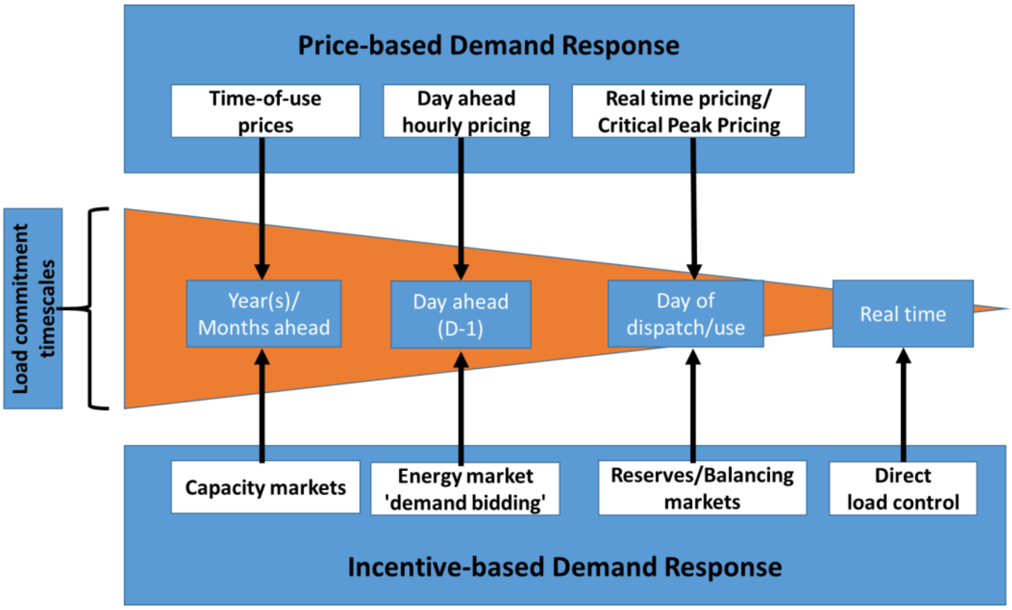
In other words, the (intended) response of customers availing of incentive based demand response programmes is known in advance to the market operator. In this way, incentive based schemes do not only require that demand response is based on price signals, which is also the case for price based programmes; it also factors the promised or intended demand response into price formation[7]. In this way, incentive based schemes are even more dynamic than so called dynamic real time prices.

In addition to the explicitness or implicitness of the demand response, timing is also a very important consideration for system operators and policy makers. The closer the system is to real time, the greater the need for accurate price signals and system operator control and reliability. Tools such as time of use tariffs (on the price-based side) and capacity procurement can be determined or procured several years or months ahead while real time pricing and emergency.

---

[7] This of course is not always the case. For example, in some US incentive-based schemes, demand response is a price taker and cannot set the market clearing price.

Figure 2-3 Types of price- and incentive-based demand response by commitment timescale



The above figure[8] picture provides a simplified view for several reasons. Firstly, both types of demand response overlap or converge; incentive based DR can facilitate smaller actors acting through demand aggregators while price based DR can involve smaller customers facing wholesale market prices. Another way to look at the difference is that price based demand response can be viewed as non-dispatchable or controllable (hence the term implicit) while incentive based demand response can be seen as dispatchable or controllable (e.g. explicit). Secondly, while price and incentive based demand responses are not substitutes (a customer can in theory engage in both), in reality, the success of one type of demand response will dull the impact of the other. For example, significant demand response in the wholesale price will flatten retail prices. Nevertheless, given the different of customers which are being targeted, at least in the short term, both types can be encouraged. Finally, the above diagram presents a very tidy view of a demand response framework; in reality, there is no market in Europe which offers all of these different demand side opportunities to customers.

2.2 Benefits of demand side response

Both types of demand side response can contribute, on a global, high level basis, to increased competitiveness, security of supply and sustainability in a large number of ways.

[8] The figure above is based on the US system for demand response so many of the concepts and time lines may differ from those in use in the EU. It, nevertheless, is informative as it provides a good overview of how price and incentive based demand response overlap and differ.

In terms of competiveness, this encompasses two distinct policy objectives. The first is direct and is to further increase competition and consumer choice within energy markets. The second refers to a broader, more indirect objective of maximising innovation, enterprise and job creation in the energy sector and beyond. For example, in terms of direct benefits, end customers can better manage their use and therefore reduce their bills while larger industrial customers can be compensated-for by turning down their system demand during high peak price periods in exchange for payments, thereby indirectly increasing 'competiveness'[9]. Demand response can also encourage innovation through knock on effects on storage and automation technologies.

As regards security of electricity supply and system operation, there are a number of policy objectives related to ensuring that electricity supply consistently meets demand; increasing fuel diversity in electricity generation, and maintaining and upgrading networks to ensure efficient and reliable electricity delivery to customers. Specifically, and as noted above demand flexibility can directly assist in providing additional long- and short-term electricity system security which can offset challenges related to greater penetration of variable wind and solar renewables on the supply side, which indirectly helps diversify the EU's electricity generation fuel mix.

Finally, in terms of greater sustainability, two main predominately indirect policy objectives fall under this heading. The first is the acceleration of growth of renewable energy resources and the second is to enhance the efficiency of electricity use and realise savings in electricity use. For example, and as noted above, greater flexibility can facilitate the greater penetration of renewables while demand response generally leads to less fossil fuel-generated power.

It should be noted that as system security standards are robust in most European countries, the absence of demand response in effect translates into higher costs (rather than black or brown outs) for system operators, market participants and customers. Therefore, the main indicator for success of a given demand response is an increase in cost efficiency. In detail, demand response can lead to:

- improved price formation: increased access to markets and exposure to real time prices increases the elasticity or responsiveness of customers to market prices, thereby lowering prices at peak and increasing them at

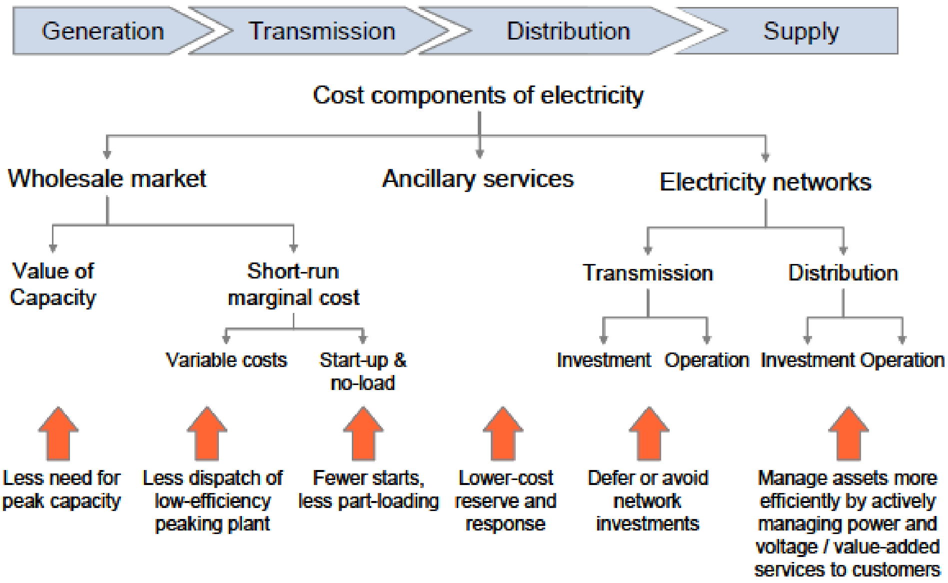
- provision of system services: demand response can help improve how electricity generation and consumption are balanced in real time

[9] The question of demand response's impact on competitiveness can be complex where there is a potential breach of state aid rules if the demand response regime in question is designed in a way which may only benefit certain participants. Therefore, the term 'competitiveness' may need to cover the performance of all actual and potential electricity market participants in order to avoid any discrimination.

- reduced investments in generation and grids: peak load reductions and shifting can lead to avoided or delayed peak generator and network investment.

The diagram below presents the potential benefits of demand side response in terms of where and how they accrue across the electricity value chain from the upstream wholesale market to the end customer connected to the distribution system.

Figure 2-4 Benefits of demand response across the electricity 'value chain'[10]



For example, benefits can manifest in terms of avoided generation and network costs which translate to lower wholesale (energy and capacity) market prices, ancillary market (reserves, balancing and other) prices and network prices/tariffs costs. As these benefits can accrue to different actors across the value chain, the actor causing the benefit may not be the same actor who benefits. This can result in inaction in the absence of some form of benefit transfer arrangement. While this may have been possible in a sector characterised by one vertically-integrated utility it is more challenging in a deregulated liberalised sector with many different players, all of whom have different incentives. Hence the delivery of a demand response framework requires intervention from public authorities, namely regulators.

Finally, how and when the abovementioned benefits accrue and 'trickle' down the supply chain to end users is of fundamental importance. For example, and as presented in the table below, a retail customer will see direct benefits from responding to real time prices (e.g. through a lower bill by shifting consumption from expensive peak times to less expensive off peak periods) while customers

---

[10] CER/Utility Regulator, *Single Electricity Market: Demand Side Vision for 2020*, Consultation paper, August 2010.

participating in the wholesale markets via incentive-based (due to reliability payments) demand response schemes may also see incentive payments. By responding, the short term impacts in terms of improved price formation and the provision of reserve capacity/balancing energy system services will lower prices for all on the demand side, thereby potentially leading overall to greater or 'social' benefits for other customers who did not respond. Of course the impact which this has on investment is more long term and nuanced, with existing peak generation plant making a lower surplus during peak periods and relying more on other sources of income such as long term capacity payments.

Figure 2-5 Benefits of demand response across the electricity 'value chain'[11]

Type of Benefit	Recipient(s)	Benefit		Description / Source
Direct benefits	Customers undertaking demand response actions	Financial benefits		• Bill savings
		Reliability benefits		• Incentive payments (incentive-base demand response)
Collateral benefits	Some or all consumers	Market Impacts	Short-term	• Cost-effectively reduced marginal costs/prices during events • Cascading impacts on short term capacity requirements and LSE contract prices.
			Long-term	• Avoided (or deferred) capacity costs • Avoided (Or deferred) T&D infrastructure upgrades. • Reduced need for market interventions (e.g., price caps) through restrained market power.
		Reliability benefits		• Reduced likelihood and consequences of forced outages. • Diversified resources available to maintain system reliability.
Other benefits	• Some or all consumers • ISO/RTO • LSE	More robust retail markets		• Market-based options provide opportunities for innovation in competitive retail markets.
		Improved choice		• Customers and LSE can choose desired degree of hedging • Options for customer to manage their electicity costs, even where retail competition is prohibited.
		Market performance benefits		• Elastic demand reduces capacity for market power • Prospective demand response deters market power
		Possible environmental benefits		• Reduced emissions in systems with high-polluting peaking plants
		Energy independence/ security		• Local resources within states or regions reduce dependence on outside supply.

One of the main contentious issues is whether and how to compensate demand response customers for the collateral[12] or social benefits they cause. Some argue that demand response 'is its own reward', and that exposure to real time prices and capacity payments is sufficient while others saying that they should be compensated through energy markets as well. This issue is discussed further below.

[11] US Department of Energy, *Benefits of demand response in electricity markets and recommendations for achieving them*, February 2006.

[12] The term 'collateral' effects is in use in the USA and is simply meant to signify those benefits which occur to all or a large number of customers due to demand response that go beyond the benefits which typically accrue directly to the customer undertaking the demand response. As a general statement, the terminology used can be streamlined and explained in the next stage if the project.

2.3 Demand response as an answer to new challenges

2.3.1 Background

Demand response, liberalisation & technological change

While electricity markets have only been in place in most countries since the early 2000s, demand response has been around a lot longer. Indeed a large number of, albeit, centrally-regulated demand-side 'management' schemes have been in place since the oil crisis of the 1970s, and many of these have been operated successfully. The question therefore is why the subject is getting increased attention at the moment.

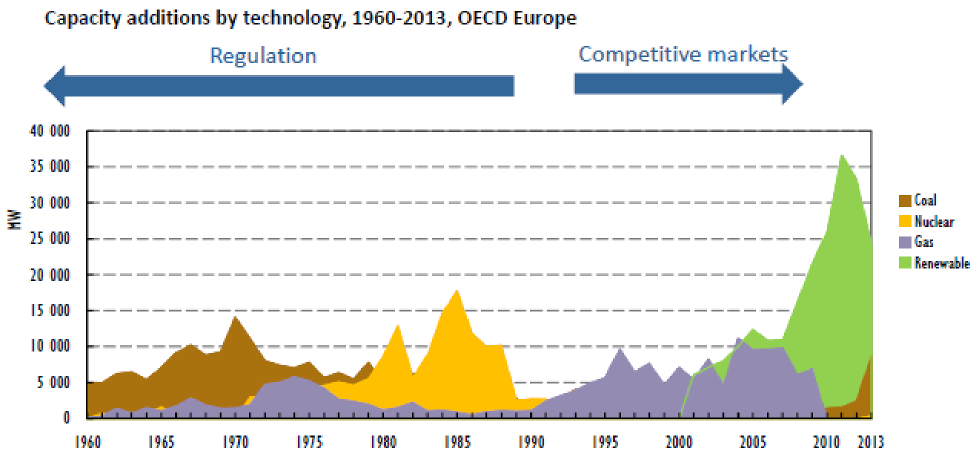
Centralised utility driven demand side management programmes emerged in the USA in the late 1970s as means to reduce growing energy costs. This system, which was quite successful, changed somewhat with the emergence of flexible gas generation plant in the 1990s, which in turn reduced the need for peak demand response, as well as by market liberalisation, which reduced the incentives for previously integrated utilities to invest in demand response. The Californian energy crisis of 2000/01, however, saw the re-emergence of attempts to increase the by then neglected role of demand side resources in electricity market. By this time, however, the focus had shifted somewhat from energy conservation goals towards using demand as a means to reduce market power at times of supply shortages. Liberalisation of the market also provided for new services while market opening has allowed customers to be more active, at least in theory.

Both developments meant that the market for demand response shifted from centralised utility led programmes to decentralised provision overseen by impartial, independent regulators. In parallel, the development of new information technologies and related devices (e.g. smart metering and displays) from the early 2000s have increased the accuracy and availability of data on demand behaviour; they also have increased customers' responsiveness/ elasticity through increasing their ability to respond to system need and prices.

Impact of growth in variable RES and phase out of fossil fuels

In addition, and perhaps most importantly, EU and international energy and climate goals have required a very large growth in investment in RES, most of which is variable and inflexible. The figure below shows how electricity generation technology has changed over the last 60 years, with peaks in investment in gas plant coinciding with market liberalisation between 1990 and 2010, which has been followed by huge growth in MW terms by variable renewable capacity.

Figure 2-6 EU generation capacity plant additions since 1960[13]



The growth in variable RES has resulted in a fundamental change in how electricity supply needs to be managed.

On the generation side, the increased penetration of variable and inflexible RES has increased the challenges faced in keeping demand and supply in sync. This has meant that TSOs, DSOs and suppliers/ BRPs need significant more short-term emergency/flexibility (e.g. reserve capacity and balancing energy) resources across the system. In addition, given the negative impact which RES capacity additions has had on the economics of more conventional flexible capacity, policy-makers in certain Member States and internationally (i.e. in the North-west USA) have introduced separate capacity or long term reliability markets. Finally, energy markets based on short run marginal costs, or SRMC, have been affected by the increased penetration of variable RES; in some places the once predictable peak is now random with prices peaking depending on whether or not there is wind or solar power[14] on the system. This is in contrast with 'old' RES technologies such as hydro which varied by year or season and not by day. This unpredictability will most likely narrow the difference between peak and off-peak prices; in reality prices will from onwards change more randomly from hour to hour.

These developments have not only increased the need for demand resources, they have also changed the type of response required; with greater supply inflexibility there will be an increased premium, in relative terms, on the ability to respond in real-time (e.g. through real-time pricing and balancing/reserve markets). The box below presents an example of how a successful, centrally administered peak reduction scheme in Ireland needed to change due to, amongst other reasons, significant increases in variable wind penetration.

---

[13] IEA, *Repowering Electricity Markets: Market Design and Regulation during the Energy Transition*, Presentation, July 2015.

[14] While solar power is more flexible than wind, it still represents a relatively inflexible form of power supply.

Text box 2-1 Example of impact of increased RES penetration on existing demand reduction programmes

Ireland's Winter Peak Demand Reduction Scheme (WPDRS)
& the impact of addition variable wind power on its effectiveness[15]

Background to the WPDRS

In Ireland, demand for electricity over the winter period is very "peaky". Ensuring security of supply is expensive and encouraging customers to manage electricity usage can reduce costs.

The Winter Peak Demand Reduction Scheme (WPDRS) was introduced in Winter 2003/04 as an incentive to larger business customers to reduce electricity consumption during the power system's peak hours (5 pm to 7 pm) in winter months. This scheme was open to customers who could choose their supplier (pre market opening in 2007) and who had quarter-hour interval metering in place.

Customers applied in advance through their supplier to join the WPDRS. In 2003/04, each customer committed to reducing consumption between 5 and 7 pm every business day from November to February. This reduction was achieved through either reducing energy use or utilising on-site generation.

The scheme was based on rewarding actual and reliable demand reduction against a historical benchmark or baseline. In 2003/04, the total available payment was quite large and amounted to €210/MWh. Of this total, €160 per megawatt was a reliability payment and €50/MWh was an energy payment.

Results

In terms of results, in 2003/04, a total of 639 customers was eligible to take part in WPDRS and 186 (29%) signed up. A total of 106MW of committed load reduction was offered by these customers, whose total baseline demand was 410MW. The demand reduction achieved through the WPDRS led to the 2003/2004 winter peak being 1.8% lower than the 2002/03 peak, even though demand for the entire year increased by roughly 3%. The load reduction achieved was quite reliable on a daily basis; 95% of the time, the achieved load reduction lay between 72MW and 88MW.

Changes resulting from the new market and increased penetration of wind power

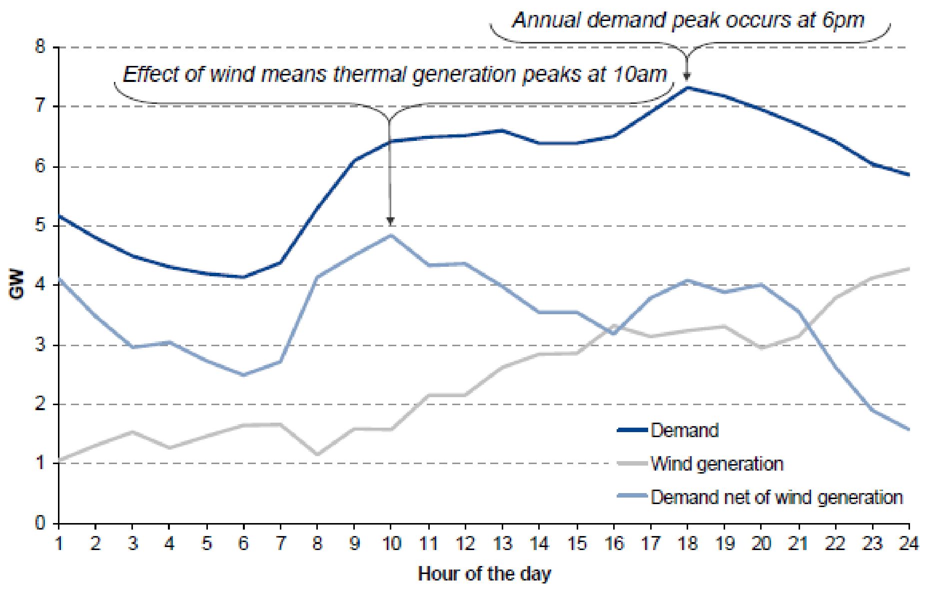
One of the reasons why the above scheme was needed was that there was an absence of a market based alternative. In other words, there were limits on the ability of large customers to participate in a wholesale market. The introduction of new wholesale market arrangements from 2007 onwards has led to the termination and replacement of the scheme in 2012 by a market based alternative.

Another important change concerns the evolution of 'demand peak periods' as wind RES penetration has increased. With greater wind generation in Ireland, there was less certainty over when dispatchable back-up generation and demand response would be required thereby making the peak period harder to determine. Hence, the time when the demand response was needed often fell outside the traditional 5 to 7pm hours, as illustrated in the figure below.[16]

---

[15] IEA DSM, Case Study – Winter Peak Demand Reduction Scheme. Found at: http://www.ieadsm.org/article/winter-peak-demand-reduction-scheme/

[16] CER/Utility Regulator, *Single Electricity Market: Demand Side Vision for 2020*, Consultation paper, August 2010.



To conclude, while regulated peak reduction demand schemes – predominately focused on system security have been effective, their use has become less useful given that flexibility is now required more and more often outside of traditional peak periods. Therefore, a more flexible, market based is required.

While it is not fully clear how generation and related (e.g. storage) technologies will develop in the coming years, given the long term aim of the EU to decarbonise the energy sector, it can safely be assumed – even if RES subsidies are phased out – that a significant proportion of new investment in electricity generation over the coming years will be in variable RES sources

Beyond generation, the advent of variable RES has led to an increased strain on the transmission and distribution networks, which has led to significant growth network reinforcement (e.g. investments in new or upgraded network) costs in both urban and rural areas. However, the development of so-called smart grids, of which demand response is a key component, should slow the need for, and cost of, this grid reinforcement. For example, price-based demand response tools that links end user tariffs with underlying time-varying network (and generation) costs should reduce the need for reinforcement of peak-demand driven higher voltage networks while greater local control of the network by DSOs can reduce LV costs. Cost-reflective connection charging can also lower network tariffs as it avoids a situation where a large proportion of the usage tariffs paid by existing users is comprise of fixed, new-connection costs.

Changing consumption patterns & new forms of flexibility

In terms of future demand, the policy goal to eliminate fossil fuels will see a move towards greater electricity usage for space heating (i.e. for heat pumps) and transport (e.g. electric cars). Some put this as resulting in a 50 percent increase in overall electricity consumption and a 100 percent increase in peak demand. For example, the UK anticipates a growth in peak demand of 32GW (up from circa 55GW) between now and 2050 due to these technologies. As these demand drivers will be driven by end consumers, they should drive growth in both generation as well as on all parts of the network.

In terms of mitigating the challenges posed by inflexible variable RES and high growth in electricity demand, it is clear that any provider of 'flexibility', and not just demand response, will be in a strong position to meet these challenges. Therefore in terms of alternative solutions to demand response, possibilities include storage (e.g. behind-the-meter or system connected), flexible generation and greater interconnection (i.e. to diversify and better make use of existing resources). The EU and Member States is currently pushing all four of these forms of flexibility through different instruments and hence is not 'picking a winner'. While this approach could possibly be seen as duplicative, it nonetheless allows the EU to hedge its bets should one approach not live up to expectations. For example, if technologies with large sunk costs and significant R&D lead-times such as electrical storage do not improve as fast as expected, the EU can possibly fall back on other less capital-intensive increased demand response and other forms of flexibility if need be. This view may make sense as demand response is relatively less dependent on technological development than possible options such as storage.

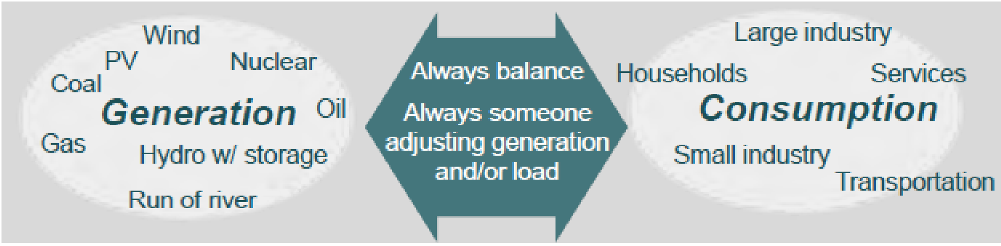
In terms of how the different 'alternatives' would interact, one view is that if storage took the value of demand response would diminish somewhat as more and more flexible generation or storage comes on line to a point where demand response may no longer be seen as necessary. Another contrary view is that demand response can actually act as a catalyst for innovations like storage. For example, tools such as real time pricing, may actually accelerate the roll-out of storage, in particular if combined with RES. Overall, from a flexibility alternative or substitute point of view, demand response would appear to be a positive least expensive development and may represent a 'no regrets' option so long as demand response is implemented in a way which is:

- responsive to actual needs e.g. not just to long term somewhat static needs for generation and network reinforcement but also to more dynamic energy market signals and short term needs
- reliable: the demand response will deliver what is expected
- proven to work: action is taken to allow and incentivise customers to response;
- subject to robust CBAs where benefits exceed costs (including customer inconvenience) and
- remains voluntary.

Different national 'starting points' for demand response

Regarding national starting points, and as can be seen from the figure below, there are a range of variables which cause each Member State to differ from another, even if the system always has to be in balance.

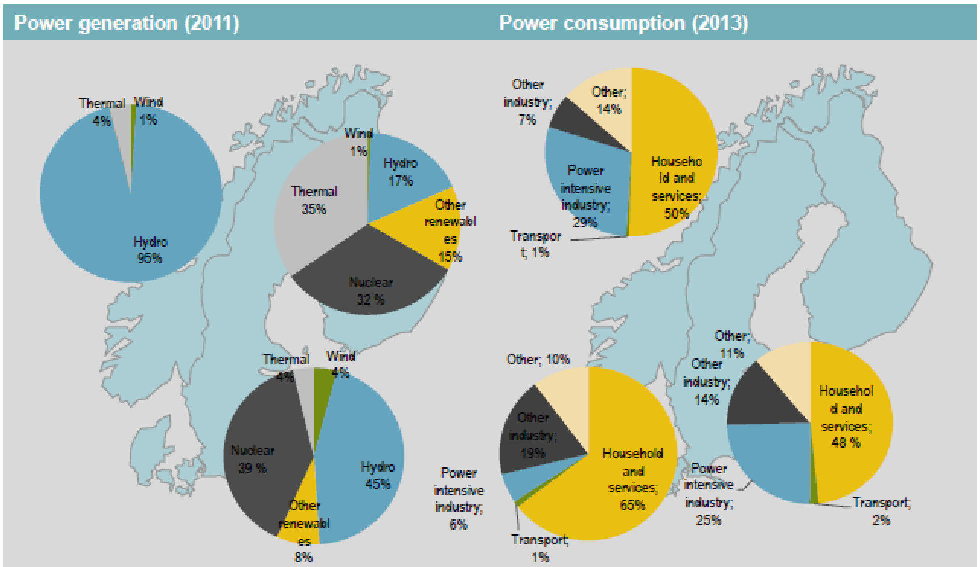
Figure 2-7: Differing generation and consumption variables



Source: THEMA (2014), *DR in the Nordic electricity market. Input to strategy on demand flexibility*

Even in the Nordic region where gas is not used for heating, there are still a range of national generation and consumption differences. Therefore, there is no one-size-fits-all solution to the 'inflexibility' challenge.

Figure 2-8: Differing generation and consumption characteristics in the Nordic area



Source: THEMA (2014), *DR in the Nordic electricity market. Input to strategy on demand flexibility*

Some differences – like air conditioning – will endure, while others may be temporal and may diminish over the next decades. In this vein, EU policy is driving the different markets to converge in a number of ways. For example, increased interconnection across the EU will probably mean that variations in supply, and in prices, will occur in many regions. This would mean that the benefits for flexibility of greater interconnection may (i) cause problems for certain countries and (ii) may diminish as the EU becomes more and more interconnected. In addition, a possible fall in the output of power intensive sectors across Europe may mean that there would be less large scale demand response available and that smaller customers may need to fill the gap.

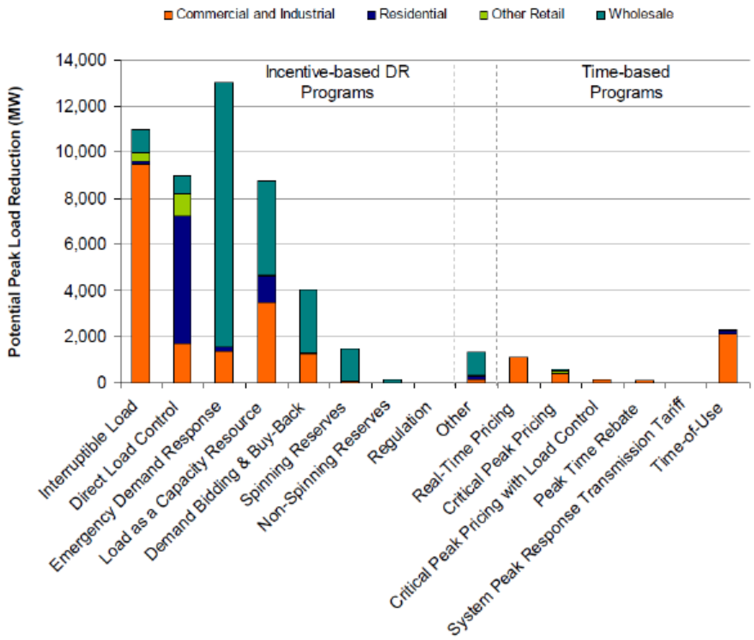
2.4 Potential and reality of demand response

While a lot has been written about the potential demand response, there is not a huge of evidence as to whether this potential is fully attainable and at what cost. In terms of the main benefits present above – better wholesale market price formation, improved supply of system services and lower investment in capacity – there is a limited and perhaps somewhat biased amount of information available.

For example, with regards to peak demand reduction potential, which if sustained leads to lower investment in peak capacity peak, a review of the literature suggests that while demand response could conceivably in the long term shave between 15 to 20 percent from peak demand and 10 percent from energy consumption, the real response may be closer to 1 to 10 percent peak demand reduction and a 0 to 5 percent overall energy consumption reduction[17].

With regards what type of demand response has what potential, it is not clear from the literature how much of this expected peak demand response is attributable to price-based and incentive-based demand response, and within these two categories what tool would deliver what response. Nevertheless, in 2011, the US FERC noted that the vast majority (92%) of peak reduction potential of the demand side resources will come from incentive based demand response, at least in the short run, while only 8% would come from priced based programmes (time based in the figure below).

Figure 2-9: Estimated price and incentive based demand side potential in the USA



Others suggest that while incentive-based demand response may be more important at present, the roll-out of smart meters, new real-time or critical peak prices and automated control technologies increase the importance of price based demand response in the coming years[18].

[17] Jacapo Torriti, *Peak energy demand and demand side response*, 2015.
[18] Brattle, *The Five Forces Shaping the Future of Demand Response (DR)*, presentation, February 2015.

In addition, and aside from the effectiveness and range of the different types of products, another important feature of the US analysis presented in the figure above relates to how the different types of response product suit different types of commercial and industrial, residential and wholesale customers. For example, it is expected that demand response will be most effective in contributing to reserve capacity/balancing energy needs (also known as emergency demand response in the US) and that most of this will come from demand side market participants (including aggregators) acting directly in the wholesale market. On the other hand, the contribution to impacting the energy market (MWh; also known as demand-bidding and so called 'buy back') seems to be less interesting. This however may change now that the US federal courts have in January 2016 given the go-ahead to the FERC and regional system operators to compensate demand side participants for energy demand bids. Overall, and in contrast to generation plant whose core business is the energy spot market, it would appear on this evidence that demand customers' main preference is to provide reliability (reserves/capacity) rather than energy services. The US market for demand response is further explored in the next section.

Another interesting aspect of the above is that residential and other small customers are seen as being important for incentive based schemes, albeit through demand aggregators via direct load control.

As this assessment exceeds current expectations in Europe, one of the main questions to be asked is whether the US potential is relevant for the EU. In terms of whether such potential is possible in Europe, this is not clear. For residential customers, US high residential consumption per capita (double the EU's) and summer time air conditioning driven peaks would suggest that there is significantly less potential in Europe. On the other hand, the expected growth of electricity demand in Europe due to heat pumps and electric cars as well as the variation in supply due to RES may suggest that both jurisdictions could converge[19]. Another factor is the very high level of distributed or back-up generation available in the USA. On the industrial side, EU industrial electricity consumption is higher.

2.5 Prerequisites and enablers of price and incentive based demand side response

The above benefits do not come automatically. Achieving greater demand response is seen as requiring the following:

› Increased consumer awareness, buy-in as well as protection and simplicity: Customers need to be aware of the potential benefits of demand response. This is particularly the case for smaller customers and **price-based demand response**. However, and despite the fact that demand response has been promoted by certain policy makers, regulators and utilities for a number of

[19] ACER, *Demand side flexibility: the potential benefits and state of play in the European Union*, 2014.

years, customers have not, to date, been fully empowered and properly rewarded. In short, one prerequisite is that customers are engaged and incentivised to respond. Another is that customers need to be able to know how to act and that they feel confident in doing so. Flat tariffs – regulated or not – protect customers not just from time-varying tariffs but also from time varying bills. Against this background, many customers may be averse to more risky tariffs, even if they would most likely benefit overall.

› Methods to measure changes in consumer behaviour[20]: One of the main barriers to demand participation has been the lack of a means to measure customer usage at any given time and communicate price and other signals to customers, as well as communicate consumer actions to other market actors in real time. While there are disagreements over the extent to which price and incentive based requires new technologies[21], the advent of smart metering and related customer displays in the 2000s – in particular for small business and domestic customers – has strongly facilitated the receipt by customers and other market actors of better information on actual usage, which has in turn facilitated the offering of static and dynamic time of use tariffs/ pricing contracts. This has, in turn, increased customers' price elasticity from -0.1 can increase significantly in the longer term (to over -0.2) where response and energy shifting technologies are available. This is predominantly an issue which thwarts price-related demand response given that most larger customers who will provide most of the demand for incentive based demand response already have interval metering in place and *should* have the option face cost reflective tariffs.

› Incentives to encourage changes in consumer behaviour: The availability of smart metering and information on usage does not automatically mean that customers are offered the right incentives[22]. For example, suppliers may not have an incentive to offer such tariffs or such devices/information, especially when they are part of larger company which also has a generation wing. Indeed, for integrated generation-supplier companies, high peak prices can result in significant profits, which would be eroded by increased demand side response. Despite the benefits which flexibility can provide to suppliers (better portfolio optimisation, lower balancing and constraints management costs), this means that certain integrated companies may not be fully incentivised to promote demand response, which in turn may have led to the entry into the market of independent demand aggregators and ESCOs.

---

[20] It should be noted that the benefits of smart metering go beyond demand response benefits. For example, benefits also accrue to suppliers and network operators in terms of better revenue control.

[21] In theory, demand response can be based on historical profiles which do not *per se* require individualised interval data, which smart metering helps provide. However, there are challenges in accurately defining such profiles for each and every customer in the absence of data.

[22] The term 'right incentives' can mean several things. In this regard we consider this to relate to tariff structures which reflect underlying costs. Though there are a number of non-efficiency related criteria to consider when designing tariff structures, tariffs which do not reflect underlying temporal wholesale market conditions and network cost drivers cannot be consider to be fully incentive-based. Factors which are outside the utility's control – such as taxes and levies – can also play a role in dampening price signals.

On the networks side, while network assets are built to meet peak demand, the tariffs charged are often partially capacity (kW) based, or are based on an average kWh. Such tariffs dull price signals and reduce incentives to respond. Finally, flat rate taxes and levies will also dull price signals. Therefore, prices which reflect underlying and time-varying costs are required – the more dynamic the tariff structure, the greater the response one would expect.

Customers need of course to be incentivised. This depends on a range of items, including but not limited to time-varying prices. For example, the proportion of an electricity bill in a person's income is important, which means that energy intensive industrial customers and low income residential customers may be more interested. The proportion of the bill which is variable is also important – if the bill is predominantly flat or capacity based, there will be substantially less response. Where time based tariffs are offered, their take up may still be thwarted by regulated prices; likewise they may be set at a level which do not sufficiently reward customers for the system-wide or 'collateral' benefits which such tariffs should reflect.

› Capacity to respond: Finally and most importantly, as a discussed above, customers need to be able to and willing to respond. This is a function of a number of factors, including the cost of distributed generation, the degree to which demand can be moved or shifted which may be the case in particular with electric heating and cooling, and the level of automation which can be applied. As it can safely be assumed that many customers will not change their habits entirely, the lack of automation means that a large proportion of demand, and in indeed customers, cannot respond at all.

All-in-all, even when all the above challenges are tackled, there will always be a certain level of customer inertia to price related demand response. Part of this inertia relates to the fact that responding to varying prices requires action on the part of smaller customers. In contrast, through intermediaries pushing **incentive based demand response** such as independent or supplier demand aggregators, customers can still benefit without directly participating themselves in the market which involves significant transaction costs and overcoming other barriers. Here, there remain a number of substantial barriers. In short, incentive-based demand response also requires the:

› Removal of market barriers to demand side participation on the wholesale markets[23]: In terms of market barriers, electricity wholesale market rules are complex and require a certain level of risk and expertise. For this reason, market operators/TSOs often require participants to be of a certain size or provide financial security. This excludes many demand customers, whose core

[23] The term wholesale markets here refers to energy markets (short run marginal cost bidding, MWh), short term reliability markets (e.g. known as reserve capacity (MW)/balancing energy markets (MWh) in the EU or emergency markets in the US) and long term reliability markets (e.g. known as capacity markets in the EU and US even though design parameters variable considerable from one Member State (EU) or RTO (US) to another, MW).

business is not electricity, from participating directly in the market. Recent years have seen the entry of 'demand aggregators' into the market who act on the wholesale market on behalf of such excluded customers. The growth of such services, however, still requires equitable access to wholesale markets for demand side resources, which in turn is affected by market and grid rules which have been designed with generation plant in mind. Therefore, these legacy rules may need to be amended and tailored to allow for greater demand aggregation and demand side participation. This does not just mean the removal of market barriers; it also means equitable access to reliability-related wholesale market incentives such as capacity payments. On the other hand, and to avoid favouring demand or supply, market rules may include rules to ensure that other market actors are not unduly put out of pocket.

› Ensuring that demand response is properly compensated: As highlighted above, unlike price based demands respond, demand side participation in the wholesale market through incentives impacts wholesale market price formation *ex ante*. In this way, demand response actors can lower the electricity price for everyone, including for those who did not respond. The question is whether and how these demand side actors can be compensated for the system or collateral benefits they may create.

› Creation and/or amendment of regulatory structures to facilitate demand response: Key to the development of equitable market rules are the regulatory or governance arrangements, and other flanking measures, which lead to the development of such rules. These may include rules to ensure that all parties have visibility of demand side actions through improved independent data exchange systems, the clarification of roles and responsibilities, including that of the DSO, and systems and processes to ensure efficient transfer of as well as rule-making procedures allow for the inclusion of customers and data aggregators.

For example, the diagrams below outline the changes in roles and responsibilities that demand response has brought about or will bring about in what is already a complex market structure. These changes will have knock-on impacts on data exchange and contracting.

Figure 2-10 Example of a 'traditional' market design framework[24]

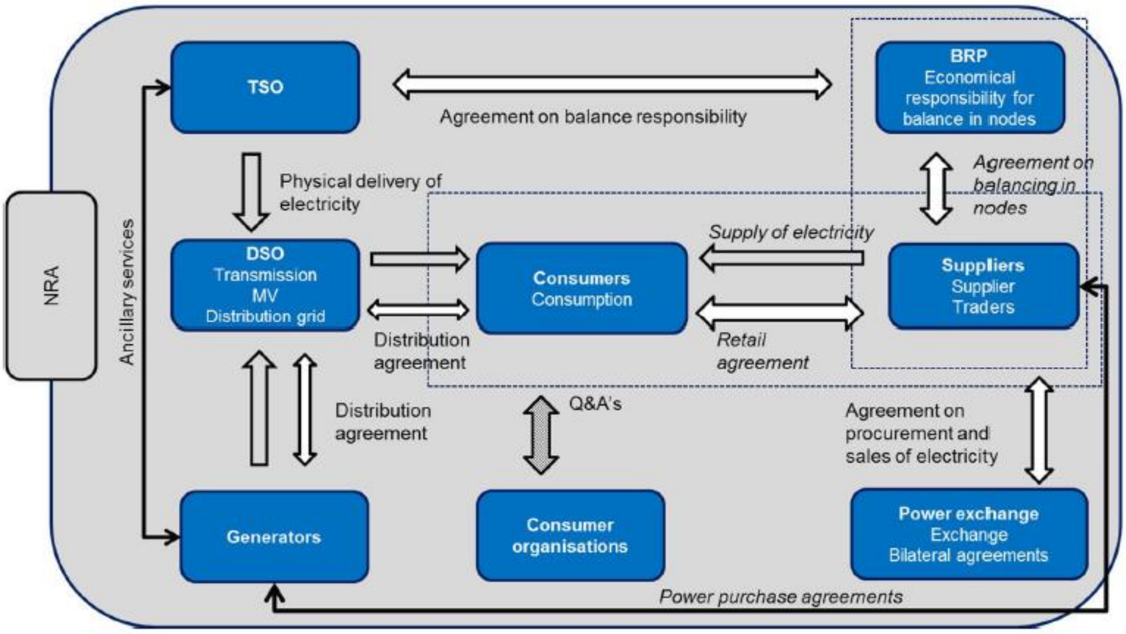
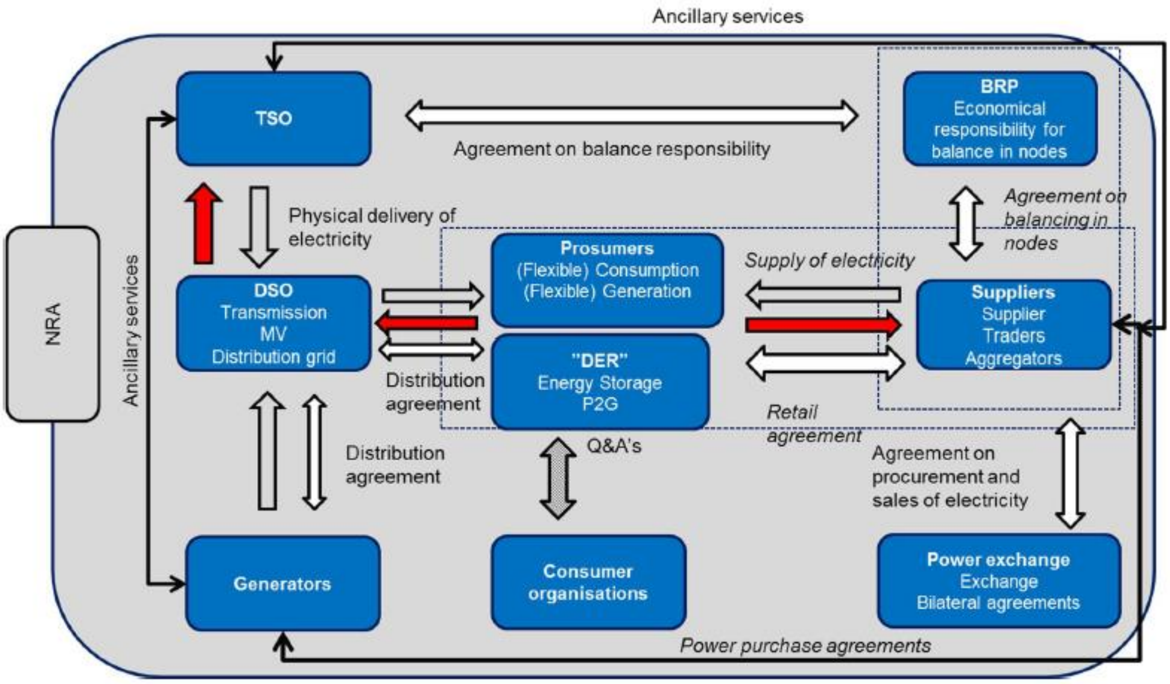


Figure 2-11 Example of a new market structure to accommodate demand response



As can be seen, the move from a 'traditional' to a 'new' market structure entails more actors (e.g. addition of demand aggregators and distributed energy resources (DER) consumers, change of consumers to 'prosumers'), more relationships (i.e. represented by red arrows) and changed relationships (between suppliers/ traders/

---

[24] SWECO, *Study on the effective integration of Distributed Energy Resources for providing flexibility to the electricity system*, April 2015.

aggregators, the DSO and the TSO). In regulatory terms, these new actors may force a rethink on the part of regulators on how the industry should be governed. For example, for competition/conflict-of-interest reasons customers may be able to contract separately with aggregators and suppliers thereby ending industry practice of the supplier acting as the one point of contact. This will, in turn, most probably increase the neutral, hub role of DSOs and TSOs[25] both in terms of rule-making and IT/communications. These developments may also require realignment of priorities and practices amongst regulators.

In the longer term, the encouragement of both price- and incentive based demand response will in the longer term foster additional demand response resulting from home and office automation, the promotion of new forms of electricity demand (such as renewable heat pumps and electric vehicles) and the development of storage technologies which are currently undergoing further research and commercialisation. All-in-all these changes may result in an entirely different market structure by 2030, including possible measures to separate distribution companies from demand side agents such as suppliers, demand aggregators and ESCOs; a lot depends on how new high impact technological and economic changes, such as those related to automated control, behind-the-meter storage and distributed generation, progress in the interim.

[25] More information on this issue can be found at: http://www.evolvdso.eu/

3 Policy framework, recent developments & current challenges

3.1 Legislative and policy background

The liberalisation of the EU's electricity market, which began in the mid-1990s, came into effect in 2007 with the opening of the market to all customers. This meant that all customers could freely choose their electricity (and gas) supplier, and that new suppliers and generators could enter the market. This liberalisation process has also taken place outside of the EU, namely in Australia, Canada and the USA.

While the impact of this process on demand response is not black-and-white – demand response could have been further fostered under a vertically-integrated structure – the liberalisation of the sector has fostered the development of new innovative energy products and services by new and old players alike. This process is coming to fruition with the entry into the sector of demand response aggregation services and internet enabled energy-saving devices to name a few. The EU's internal energy market legislation, as well as rules on the promotion of renewables and energy efficiency, have strongly contributed to these changes.

3.1.1 The third internal market energy package

Despite the full opening of the energy markets in 2007, a range of barriers to a fully- or properly-functioning market persisted. The third energy package of 2009 was introduced to address these barriers. This package contained a variety of rules to promote competition, including provisions to separate incumbent energy supply and generation companies from the operation of transmission networks (unbundling) so as to foster fair access to the grid and market for new third, non-incumbent parties.

Moreover, to develop equitable rules on how the market should work, the EU established an Agency for the Cooperation of Energy Regulators (ACER) as well as European networks of TSOs for electricity and gas (ENTSO-E and ENTSO-G respectively), which were charged, amongst other duties, with developing detailed framework guidelines and 'network' codes for trading in electricity and gas which would be approved by the European Commission through implementing acts (e.g. through Comitology). A number of areas were to be covered in these codes, including balancing rules for electricity[26] and gas when the system is 'out of balance' (e.g. customer demand exceeds supply at any given time and vice versa), an issue which is of particular importance for the development of incentive based demand response. Also of central importance is the code on demand connections[27].

The third energy package also introduced a number of measures to promote a well-functioning retail market. This included provisions on market-based electricity pricing as well as to promote the use of so called smart meters to more accurately measure customer demand and allow for the introduction of time based prices which give customers more control over their usage and bills. With specific regards to smart metering, Member States are required to implement smart metering where there is a positive cost benefit analysis that they are required to have completed by September 2013. Based on the results of the CBAs performed, it was expected that the roll out would result in 72 percent of the consumers having smart meters by 2020. In most Member States, the regulators working with DSO(s) have been put in charge of this process. The UK is an exception wherein the regulator has worked with electricity suppliers on a roll-out CBA.

3.1.2 Other relevant EU legislation on renewables and energy efficiency

In parallel, the EU has developed a range of legislative and policy measures to achieve a number of other energy policy goals such as to increase the sustainability and security of the EU's energy supply. These other legislative provisions relate primarily to the promotion of renewables and energy efficiency and have a strong impact in particular on the need for incentive based demand response.

One of the main objectives of the Renewable Energy Directive of 2009 was to increase the total amount of electricity and other energy coming from renewable sources, to cover 20 percent of all EU supply by 2020. As the EU is on track to meet this target, this has resulted in a significant increase in the amount of variable or non-dispatchable electricity from wind and solar sources on the electricity system. As noted above, this has meant, however, that additional 'back-up' sources of electricity are needed when the wind does not blow or the sun does not shine, which in turn has required more system flexibility including from potential flexible demand sources. This need will only increase with the RES target growing to 27 percent by 2030.

The recently implemented Energy Efficiency Directive of 2012 has played an even more central role in driving demand flexibility. First, in addition to including additional and clear provisions on smart metering and billing based on

[26] The balancing code is due to be finalised in late 2016. The latest draft version can be found at: https://www.entsoe.eu/major-projects/network-code-development/electricity-balancing/Pages/default.aspx (accessed 23rd February 2016).
[27] Commission Regulation establishing a Network Code on Demand Connection, October 2015.

consumption information (Articles 9-11) , the Directive also includes a series of policy measures – in Article 15 – which require Member States to promote demand response. These includes provisions to ensure that:

- National regulatory authorities encourage demand response to participate alongside supply in wholesale and retail markets
- Access and participation of demand response in balancing, reserve and other system services markets is promoted
- High-efficiency cogeneration operators can offer balancing service and other operational services
- TSOs and DSOs treat demand response providers, including aggregators, in a non-discriminatory manner

With regards to the latter bullet, the Directive includes a provision (Article 15.8) that specifically allows for smaller customers to participate in the market through intermediaries such as demand aggregators. Specifically, the Directive requires that demand response service providers, representing customers, have access to organised markets on equal terms to suppliers.

Unfortunately, to date, the implementation of Article 15, and in particular Article 15.8, has been mixed at best. Reflecting the results of a 2015 industry-led Smart Energy Demand Coalition (SEDC)[28], an unpublished 2016 study by the European Commission's Joint Research Centre (JRC) notes that most Member States have not acted sufficiently to remove barriers to price- and incentive-based demand response. Despite this, given the growth of demand aggregators over recent years, a certain level of progress has been made. Indeed as the deadline for transposition of the Directive was mid-2014, it is still early days in terms of implementation of incentive based demand response measures. The current situation is further explored in the section below.

3.2 Progress made since the IED in 2009

Despite the abovementioned potential and legislative framework, there has only been a limited level of progress made in this area over the last several years Therefore, in the words of the European Commission[29] it appears right to say that "*the potential of the demand side in markets is currently underutilised*".

[28] SEDC, *Mapping demand response in Europe today*, September 2015.
[29] European Commission, Communication, *Delivering the internal electricity market and making the most of public intervention*. November 2013.

3.2.1 Smart metering

With regards to the availability of smart metering that is needed for dynamic pricing for smaller customers[30], according to the Commission's 2014 Communication on "*Benchmarking smart metering deployment in the EU-27 with a focus on electricity*", 17 Member States will proceed with large scale roll-outs of electricity smart meters by 2020 or have already done so. The remaining eleven either reported an inconclusive or negative CBA (seven MS) or had not yet reported back to the Commission (four MS). Of the main markets, Italy has completed its national roll-out with the UK, France and Spain on track for completion by 2020. Germany presents a more mixed picture with the roll-out confined to larger usage customers. All-in-all, and as mentioned above, it is estimated that 72 percent of all customer demand is expected to be covered by some form of smart metering by 2020, in little more than three years.

However, the results, and hence application of the national CBAs, need to be interpreted with caution for a number of reasons.

First, each Member State used a different CBA methodology, varying key parameters such as the time period of analysis, the treatment of meter replacement, the treatment of avoided cost of standard meters, the communications technology adopted and the need for complementary investment (meter boards etc.). This has resulted in very large differences in both estimates of costs and benefits. For example, some countries identified the costs as being in the range of 100 euros all in (e.g. meter, IT, communications and data infrastructure, installation and maintenance) while some estimates were in the range of €500 to €600, namely in Germany, Belgium and Ireland. This has complicated any cross comparison of Member State roll-out plans. The assessment of benefits has also differed considerably with some lower than €100 (e.g. Czech Republic) and some much higher at over €500 (e.g. Ireland). Overall however, the costs cluster in the area of €100 to €300 including in-house displays while the benefits are generally higher, in the region of €150 to €400[31].

Second, much of this may possibly be explained by the fact that the underlying smart metering functionalities differed considerably. With regards to costs however, there seems to be no clear relationship between cost and functionality[32]; in other words, many countries' estimated costs have been estimated on the high side. While this could be due to poor data, another explanation is that over-customisation and poor economies of scale may be the cause of high prices in certain countries. Despite this reasons, a more harmonised approach consistent with the Commission's methodology may reverse some of the more marginal inconclusive or negative CBA results. This of course depends on whether the

[30] Industrial customers should already have interval two-way metering in place. This will be verified in the next stage of the project.
[31] It should be kept in mind that all of these differences are reduced when standard CBA methodologies are used.
[32] AF Mercados EMI and NTUA, Study on cost benefit analysis of Smart Metering Systems in EU Member States, Final Report, 2015.

benefits – which are harder to gauge – stack up. For example, benefits may be biased upwards by overoptimistic estimates on energy conservation.

All-in-all it is interesting that the majority of benefits related to advantages that have little to do with demand response; they relate rather to customer service or administrative improvements in the areas of meter reading, dis/reconnection, identification of system problems as well as fraud detection and so on. Many of these benefits, however, are only possible if smart meters are rolled out across a certain geographical area. For example, a geographic roll-out would reduce meter reading costs considerably compared with a customer-by-customer roll-out. In terms of consistency across Member States, there are also considerable different estimates of the non-energy conservation benefits; for example estimates of savings from reduced theft vary significantly from country to country.

Beyond these benefits, the customer impact through demand response varies considerably, with several MS assuming that reduction in consumption and/or shifts in consumption will occur, though with little consideration of dynamic pricing in the CBAs. MS also vary whether avoided energy generation and network estimates are included in the CBA. A final difference is that many considered electricity and gas together, which reduced overall costs.

All-in-all, as the pan-EU picture on smart metering is extremely diverse, it is difficult to identify precisely what the costs of smart metering are. However certain issues are clear:

- a more standardised CBA methodology and common functionality would lead to different results, and potentially to more positive CBAs;
- increased functionality is not necessarily the main driver of costs. In fact as functionality is software driven, the incremental cost of functionality is relatively low. Rather issues related to economies of scale and customisation may be more important in driving overall costs;
- much of the benefits relate to new or increased customer services that have little or nothing to do with demand response;
- finally, many of the benefits are based on estimates and are subject to considerable uncertainty, in particular those concerning energy conservation and demand response.

With regards to how the above picture impacts demand response and the important role which smart metering plays in its development, there are a number of risks:

- while functionality is not necessarily related one-to-one to cost for new roll-outs, many smart metering programmes have been based on a CBA which does not include in-house displays (or other means of visualising consumption (for example, mobile phone application) and two way communication[33], which may severely impede real time pricing and other

[33] It should be noted that two-way communication is only needed if Internet access is not available or safe enough or for direct load dispatching.

demand side services. This may be the case in Italy where the decision to roll-out was based on avoiding electricity theft. As the lifetime of these meters is 15 years[34], the choice is between replacing stranded assets or waiting until 2030 to change the existing 'sub-functional' smart meters[35];

- as many of the benefits related to customer and system benefits depend on a geographic roll-out and related economies of scale, a customer-by-customer decision to opt for smart metering may be considerably more expensive on a per customer basis. That said, given that some of the geographical roll-out CBAs estimate a very high per unit cost, there may be an argument for opening up the market to competition, or at least allowing suppliers and/or demand aggregators choose their own solution.
- many of the conservation-related CBA benefits are based on the assumption that customers would be offered time-of-use and real time prices which are effective at avoiding investment and hence save costs; however, this has not happened outside of Sweden and Finland, as presented below. Without this progress on real rather than ideal energy conservation changes, many of the CBAs undertaken may have been negative.

3.2.2 Price based demand response

Being able to response to price signals which reflect underlying and varying costs is a fundamental aspect of demand response.

On paper, the majority of Member States already offer tariffs that vary somewhat on the basis of time. Indeed, 92 percent[36] of customers can in theory avail of such tariffs. In reality, however, this relates to dual peak day/off-peak night supplier tariffs which have been in place since the 1970s and 1980s, retail/supplier tariffs which do not require smart metering and related in house displays[37]. Therefore, there is little potential in this area. In addition, how these dual supplier tariffs are structured varies considerably with the differences in peak and off-peak prices sometimes being minimal (e.g. in Italy) and not reflecting underlying variations in wholesale and network costs.

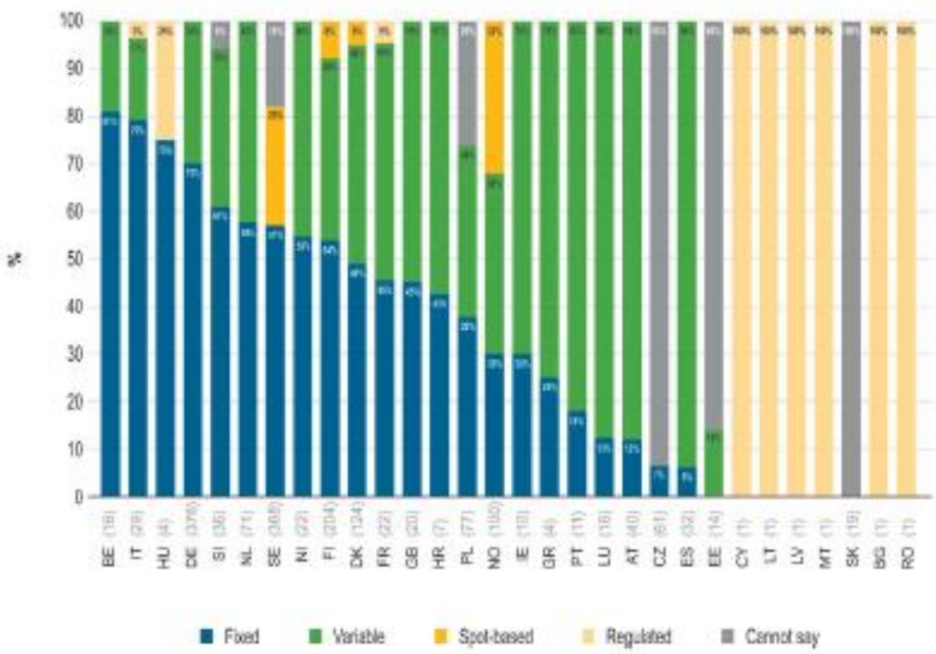
As the majority of EU Member States have yet to fully roll-out smart metering, this picture is not surprising. However, suppliers in countries like Italy which have a certain level of smart metering in place do not offer significant differences in peak off peak tariffs. Even here, results from **time-of-use** supplier tariff trails have led to unexpected results with peak morning demand falling but peak evening demand staying the same. In terms of usage, time of use tariffs in Italy have actually led in certain trials to increased usage, albeit at a lower overall 'bill' cost. Part of this is explained by the low difference between peak and off peak tariffs. Another more

[34] While the cost of the smart meters installed in Italy are of the order of 2 euros per customer and hence are not high, the costs of removing and installing new meters could be significant.
[35] This needs to be confirmed as smart meter lifetimes may turn out to be longer than 15 years.
[36] ACER, *Demand side flexibility: the potential benefits and state of play in the European Union*, 2014.
[37] All that is required is a different form of electro-mechanical meter.

fundamental problem is that such tariffs do not reflect underlying system conditions which means that they will not provide flexibility when it is needed.

In terms of countries which have introduced more robust **real time prices**[38], heavy electricity per capita users in Norway, Sweden and Finland lead the way with up to 30 percent of customers, and an even higher share of usage, opting for real time prices (yellow in the diagram below). This of course means that the remainder, or most customers, have opted to stay on fixed tariffs.

Figure 3-1 Proliferation of fixed, variable and spot based tariffs by Member State[39]



While other EU Member States (AT, BE, EE, DE, NL) are reported to offer real time pricing, their take-up is limited to a small proportion of customers. Only France has offered CPP to all customer types.

Several utilities in the USA have changed their default tariffing to real-time pricing of which customers have to opt-out. Some commentators[40] suggest that such a system would lead to significantly higher price based demand response. However, any prolonged surge in wholesale prices, such as that which occurred in Europe in the summer drought of 2003, would avert customers from exposure to real-time prices. Indeed, this is believed to have been an issue in hydro-electric dominated Norway where approximately 10 percent of residential customers are on real-time

---

[38] The term real time pricing refers to a number of models. For the most part they are linked to day ahead prices which means they are not fully 'real-time'. This will be explored in the next stage of the project.
[39] ACER, *Energy Consumers and Retail markets: Results from the 2014 Market Monitoring Report*, presentation at the 7th Citizens' Energy Forum, March 2015.
[40] Brattle, *The Five Forces Shaping the Future of Demand Response (DR)*, Presentation made at Demand Response Virtual Summit February 2015.

prices. Such an issue, however, could in theory be resolved through caps in real time prices.

A more limited version of real time pricing is **critical peak pricing** (CPP) which has been pioneered in California in the US and in France in the EU. Under CPP, for the vast majority of time customers are exposed to typical three or two period time of use tariffs. The difference is that for 10 to 15 limited time periods per year prices rise to reflect supply constraints on the system which can result in critical peak prices which are up to 10 times their normal level. In contrast with time of use customers, the peak can be reduced by between 10 and 20 percent, which is even greater than the reduction seen for real-time pricing. While the specific reason for this is unclear, it may relate to the sporadic nature of CPP peak events.

Finally, in contrast to time of use pricing, both real-time and critical peak pricing need some form of IT communications with their supplier. For example, while it is perfectly conceivable that real-time prices could be communicated to customers via the internet and not through a dedicated in-house/building display, it is assumed that this would not be consistent with two way communication[41] which may require a dedicated device.

There are a number of general issues which need to be considered here. The first is how consumer benefits from conservation and shifting usage from peak to off-peak periods are measured. Many studies look at the impact of usage change on investment needs and bill reductions. This, however, assumes that there is no inconvenience or welfare loss for customers resulting from having to either pay more at peak or change their behaviour, the real welfare benefit is less. For example, while the move flat to time-varying tariffs may result in, say a 5 percent bill reduction, the welfare is roughly half of this as the bill reduction does not take into account welfare loss[42].

The second issue, and as raised above, relates to tariff structures and the proportion of the end bill which is variable. In some jurisdictions (e.g. Germany), the part which is variable, and hence which can be charged as such under cost-reflective tariffs, constitutes less than half of a customer's bill. Related to this is that costs for services which are quite unrelated to ongoing electricity supply (e.g. such as grid reinforcement connection-related costs for new customers) are often charged to all customers, and hence old established customers cross-subsidise new connections. Flat rate taxation and renewable subsidies payments also dulls price signals.

With regards to how the above picture impacts demand response, there are a number of issues:

[41] The next version of the report, the second intermediate report will contain a full glossary of terms and definitions.
[42] The logic here is that a customer gains a greater level of utility from one kWh consumed at peak than one at off-peak. Therefore, if a customer shifted one kWh from peak to off peak, his bill would drop by the difference in the rates but he would also lose a certain level of utility or 'welfare'.

- though time of use pricing may be acceptable to many risk-averse customers, it may have a lower than expected impact on peak usage and has little or no impact on balancing and other flexibility providing demand side services.
- nevertheless, where real-time and critical peak prices are adopted, by say 20% of customers, significant changes in peak demand are possible.
- finally, to be effective, the incentives need to be right. This means tariffs that provide customers with large potential welfare gains and not just 'bill' reductions; it also means structuring tariffs to better reflect underlying fixed and variable elements of electricity supply.

Despite the potential of price based demand response[43], in the absence of a considerable push by policy makers, it will remain marginal. In any case, as price based demand response is unseen until after the response by system and market operators, it may be less important – at least today – than explicit or incentive based demand response further.

3.2.3 Incentive based demand response

Beyond retail markets, the EU *acquis* is also quite clear on the need for, and rights of, demand response participants in European wholesale electricity markets. Building on the Third Energy Package and the Energy Efficiency Directive of 2012, in its Framework Guidelines on Electricity Balancing, the Agency for the Cooperation of Energy Regulators (ACER) noted that the detailed rules to be put in place should facilitate the participation of demand response in balancing markets and inserted a specific provision in its recommendation for a Balancing Code which would enable the independent provision of demand-side response[44]. The above-referenced Demand Connection Code also caters for demand aggregation.

Despite this, progress in the EU has been sketchy. Given the lack of empirical evidence available in Europe, it is necessary to look at international experience, namely the example of its success in the USA.

As already mentioned in the previous section, there are a number of good reasons why the EU has trailed the US in promoting demand flexibility in the wholesale market. One is that the EU has significant levels of pumped hydro and hence has less of a need for demand response; another is that the difference between peak and off peak electricity use is less pronounced given the lower penetration of air conditioning and the prevalence of natural gas for heating purposes.

These differences helped to avoid the type of wholesale market price spike seen in California in 2001, which in turn acted as a driver of policy change. Moreover, the Federal Energy Regulatory Council, working with the Department of Energy, has been extremely active in pushing incentive based demand response. Part of this

---

[43] The split between price and incentive based demand response is artificial as the two can be combined. For example Price based demand response tools such as CPP can be made more effective by explicit tools such as load control. However, these tools are not in wide use.

[44] ACER, *Recommendation on the network code on electricity balancing*, July 2015.

focus may also relate to the fact that decisions on 'retail' issues such as time of use tariffing and smart meters are outside of the FERC's jurisdiction which leaves more room for focussing on how demand response can be promoted on an inter-state wholesale market basis. This situation has of course changed with the substantial growth in wind and solar power in Europe which has meant that the EU needs to catch up.

Types of product/service

In terms of what services can be offered under incentive-based demand response, and as described in the previous section, like other supply side participants the demand side can offer its services in the energy (spot) market, long term capacity market (where one exists) and the short flexibility markets (reserve capacity and balancing energy). As electricity is not the core business of most, if not all, demand side participants, they have in the past tended to have become more involved in markets where participation offers a regular payment. This means the short-term flexibility markets (US/EU) and long-term capacity markets (US), and not energy markets. Indeed, for a number of reasons certain commentators note that capacity markets are particularly suited to demand side participants.

The table below presents an overview of the markets in which the main demand response 'products' or services would be offered.

Text box 3-1 Wholesale market 'products', demand side response and resulting benefits

Product	**Energy**	**Flexibility**	**Capacity**
Benefit	Efficient dispatch	Short term system adequacy	Long term system adequacy
What it does	Delivers energy in the most cost-effective way by letting the market define the system's merit order	Enables the system to respond to short term variations in the supply-demand balance	Providers policy makers with certainty that there will be sufficient capacity in place for the medium term (e.g. 4 years)
Market instruments	Forward, day ahead, intra-day markets	Day ahead, intra-day markets, balancing markets, ancillary services	Capacity markets[45]
Role of demand response	Bids to reduce demand, which in simple terms can reduce wholesale spot prices	Short term offering of reserve capacity and balancing energy from fast response demand units	Longer term offering of capacity
Potential based on experience	Low to medium	High	Medium to high
Current cross-EU border situation	Ongoing integration (well-developed)	Ongoing cross border integration (less developed than energy)	Largely national

Experience in the US and possible application to the EU

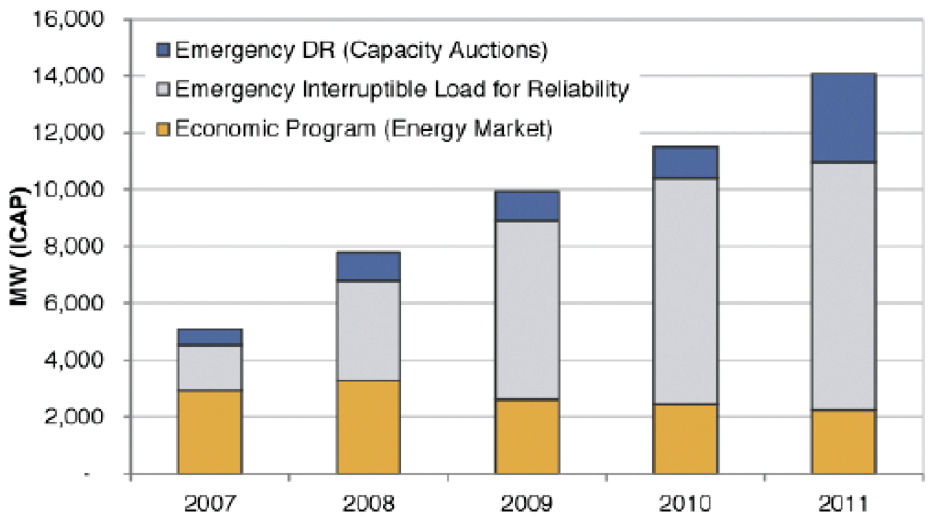
With regards to what is possible for demand side participants, the figure below presents the growth in demand response participation in reserves/balancing (emergency interruptible load), capacity (emergency DR) and energy (economic program) markets in the Pennsylvania, New Jersey, Maryland (PJM) RTO over the

[45] In reality there are range of different capacity market designs, an issue which will be factored into the analysis in the next stage of the project.

period 2007 to 2011. In terms of scale, the figure for 2011 represents just under 10% of the peak load of 160,000 MW[46] managed by the PJM.

In terms of provider, a reported 82 percent of all PJM demand response is provided by data aggregators[47]. While the PJM is a leading proponent of demand response, the situation is similar in the neighbouring regional wholesale markets of New York (NYISO) and New England (NEISO). The picture is somewhat different in the western states with markets such as California (CAISO) attracting a lower level of demand response.

Figure 3-2 Performance of incentive based demand response in the PJM wholesale markets (RAP, 2013)



The figure above also sheds light on the type of incentive-based demand response which could be expected in the EU over the coming years of demand response is promoted. With regards to the PJM, the demand side *appears* to be interested more in providing capacity and balancing/reserves and less in providing energy to be bid into the spot market. As mentioned above, one of the main understood reasons for this is the perceived need of demand side for the regular monthly capacity or reserve payments which long and short term flexibility markets provide and the relatively low likelihood of being called upon to deliver. Indeed, one of the main understood reasons for the relatively low level of demand response in California is the absence of a capacity market.

It must be kept in mind that such demand response has not occurred naturally through the actions of market participants; it has required state intervention through targeted Department of Energy policies and federal regulatory rules of 'orders' requiring that demand response is properly rewarded.

---

[46] Regulatory Assistance Project, *Demand response as a power system resource: program designs, performance and lessons learnt in the United States*, May 2013.
[47] Smart Energy Demand Coalition (SEDC), *Mapping demand response in Europe today*, September 2015.

While capacity and flexibility payments to demand response participants are relatively uncontroversial, there has been a considerable amount of discussion on how to compensate demand bids in the spot market. In simple terms, some (namely FERC) advocated compensation based on the spot clearing price while others representing electricity generation companies said that such a regime would overcompensate such bids and would be economically inefficient. This issue was the subject of a federal court case and in 2014, the future of demand side energy bidding in wholesale markets was put into question. This was not addressed until early 2016 when the federal court ruled in favour of the FERC position. It should be noted that, despite the level of discussion energy market demand biddings has generated, the capacity and flexibility markets remain the main source of demand participation; demand participation in the spot markets remains relatively low.

In the EU, certain countries with longer term capacity markets in place such as Ireland and France have been successful in attracting a certain level of incentive-based demand response. Indeed, it is less likely that such demand response would be available in both countries without these capacity payments. Concerning energy market bids, though it is early days, low levels of participation in Belgium and France would appear to reaffirm the experience in the USA that capacity and reserves/balancing are more interesting for the demand side.

That said, there is not a direct relationship between capacity markets and demand response as the UK has also introduced capacity markets but has not, to date, attracted significant levels of demand capacity, at least not with regards to capacity products spanning four years or more. Plans to auction one year products may in future result in a greater level of demand response participation.

In the EU context, capacity markets remain national in nature and there are no plans for EU regional capacity markets, even if the Commission is examining the possibility of introducing a framework for cross-border participation in capacity mechanisms as part of the energy union legislation to be adopted in late 2016. While it is premature to speculate what form such a framework may take, it is expected that open participation rules – including to the demand side – may be included as a possible principle.

In terms of the status quo, in 2014, the ACER conducted a questionnaire-based survey to assess the development of incentive-based demand response across the EU. The table on the next page presents the main results.

Text box 3-2 Member States' response to ACER demand response questionnaire – participation rules by product

Demand participation		**Existing**	**Planned**	**None**
Wholesale (energy) markets	***Participation***	BE, CZ, DK, FI, FR, HU, IE, IT, NL, PL, PT, RO, SI, SE	AT, DE, LT, UK	BG, HR, CY, EE, EL, LV, LU, MT, SK, ES
	On equal basis to generation	BE, CZ, FI, FR, DE, IE, NL, PT, SE	LT, UK	AT, BG, HR, CY, DK, EE, EL, HU, IT, LV, LU, MT, RO, SK, SI, ES
	Participation of aggregators	BE, FR, DE, IE, IT, NL, SE	FI, UK	AT, BG, HR, CY, CZ, DK, EE, EL, HU, LV, LT, LU, MT, NL, PL, PT, RO, SK, SI, ES
Balancing energy markets	***Participation***	AT, BE, CZ, DK, FI, FR, HU, IE, NL, PL, RO, SI, SE, UK	DE, IT, ES	BG, HR, CY, EE, EL, LV, LT, LU, MT, PT, SK
	On equal basis to generation	CZ, DK, EE, FI, FR, HU, ES, SE, UK	AT, BE, DE, IE, PL	BG, HR, CY, EL, IT, LV, LT, LU, MT, NL, PT, RO, SK, SI
	Participation of aggregators	BE, DK, FR, NL, UK	AT, DE, HU, IE, PL	BG, HR, CY, CZ, EE, FI, EL, IT, LV, LT, LU, MT, PT, RO, ES, SE, SK, SI
Reserve capacity markets	***Participation in primary reserves***	AT, BE, DK, FR, IE, NL, SE, UK	DE	BG, HR, CY, CZ, EE, FI, EL, HU, IT, LV, LT, LU, MT, PL, PT, RO, SK, SI, ES
	Participation in secondary/tertiary reserves	BE, CZ, DK, FR, HU, NL, SI, SE, UK	AT, DE, IE, PL, ES	BG, HR, CY, EE, FI, EL, IT, LV, LT, LU, MT, PT, RO, SK
	On equal basis to generation	BE, CZ, DK, EE, FR, HU, SE, UK	AT, DE, IE, PL	BG, HR, CY, FI, EL, IT, LV, LT, LU, MT, NL, PT, RO, SK, SI, ES
	Participation of aggregators	BE, DK, FR, DE, NL, UK	AT, HU, IE, PL	BG, HR, CY, CZ, EE, FI, EL, IT, LV, LT, LU, MT, PT, RO, SK, SI, ES, SE
Capacity remuneration mechanisms	***Capacity mechanism in place***	BE, EL, IE, PL, ES, SE	FR, IT, UK	AT, BG, HR, CY, CZ, DK, EE, FI, DE, HU, LV, LT, LU, MT, NL, PT, RO, SK, SI
	Participation in capacity mechanism	BE, SE	FR, IE, IT, UK	AT, BG, HR, CY, CZ, DK, EE, FI, DE, EL, HU, LV, LT, LU, MT, NL, PL, PT, RO, SK, SI, ES
	On equal basis to generation	SE	BE, FR, IE, UK	AT, BG, HR, CY, CZ, DK, EE, FI, DE, EL, HU, IT, LV, LT, LU, MT, NL, PL, PT, RO, SK, SI, ES
	Participation of aggregators	BE, SE	FR, IE, UK	AT, BG, HR, CY, CZ, DK, EE, FI, DE, EL, HU, IT, LV, LT, LU, MT, NL, PL, PT, RO, SK, SI, ES
Other types of demand participation	***Interruptible contracts called by supplier***	BE, FR, HU, SE, UK	CZ, DK, DE, PT	AT, BG, HR, CY, EE, FI, EL, IE, IT, LV, LT, LU, MT, NL, PL, RO, SK, SI, ES
	Demand resource called by DSO or TSO	BE, CZ, DE, HU, IT, NL, PT, RO, ES, SE, UK	AT, DK	BG, HR, CY, EE, FI, FR, EL, IE, LV, LT, LU, MT, PL, SK, SI
	Demand resource called by DSO or TSO via aggregators	AT, BE, IT, NL, UK	DK, DE, PT	BG, HR, CY, CZ, EE, FI, FR, EL, HU, IE, LV, LT, LU, MT, PL, RO, SK, SI, ES, SE

Text box 3-3 Member States' response to ACER demand response questionnaire – participation rules by type of customer/response

Demand participation		**Existing**	**Planned**
Wholesale (energy) markets	***Energy efficiency measures***	NL	
	Embedded generation	BE, FR, DE, NL	
	Time shift of demand	BE, FR, LT, NL	DE
	Demand reduction	BE, FR, DE, HU, LT, NL	
	Demand interruption	BE, FR, HU, IT, LT	DE
Balancing	***Energy efficiency measures***	-	-
	Embedded generation	BE, DK, FR, DE, IE, NL	-
	Time shift of demand	BE, DK, FR, HU, IE, NL	DE, UK
	Demand reduction	BE, DK, FR, HU, IE, NL, UK	AT, DE, RO, ES
	Demand interruption	BE, DK, FR, HU, IE, ES, UK	AT, DE, RO
Capacity remuneration mechanisms	***Energy efficiency measures***	-	FR, UK
	Embedded generation	BE	FR, UK
	Time shift of demand	BE	FR, UK
	Demand reduction	BE	FR, UK
	Demand interruption	BE, ES	FR, UK

The first thing that can be seen from the first table above on demand participation is that there are a significant and growing number of Member States who self-declare that wholesale and/or balancing markets are open to demand side response. That said the majority of markets remain closed while only a few of those that are open allow for demand aggregation. In terms of participation in capacity markets, as there less than 10 Member States with such markets, the majority of these permit demand participation. That said, even in these markets, there is still a reluctance to permit aggregation. Also of interest is that those Member States which are open to one form of demand response are open to most others (e.g. BE). Finally, the questionnaire also treats the issue of how demand participates with most of the open markets allowing for participation of embedded generation, time shift of demand, demand reduction and demand interruption.

The inclusion of embedded generation is perhaps not surprising considering that much of what is seen as demand response in the PJM and in certain Member States of the EU (e.g. UK) is actually response by back-up generation. For example, in 2013 of the British National Grid's Short Term Operating Reserve (STOR), most is provided by customers with distributed generation behind the meter; only a small proportion is actually due to reduced demand[48]. One reason for this is that while distributed generation can respond fast enough to qualify, demand reduction sources of reserve capacity is often excluded as it takes time to come on-line (e.g. more than 10 minutes). In the absence of automated control, extending such time horizons and developing more flexible rules in general may be necessary to allow for the increased participation of customers who can respond based for example on

[48] Jacapo Torriti, *Peak energy demand and demand side response*, 2015.

reduced heating and cooling. It is understood that a substantial amount of DR resources in the USA is also sourced from embedded or distributed generation.

Ongoing challenges and proposed best practices

Overall, and in spite of considerable advances in recent years, advocates for greater incentive-based demand response highlight a number of ongoing problems. These problems are numerous and have been thoroughly examined at EU level by a large number of stakeholders such as EURELECTRIC[49], the Smart Energy Demand Coalition, the Smart Grid Task Force[50], the Agency for the Cooperation of Energy Regulators, and the Council of European Energy Regulators (CEER)[51], the Regulatory Assistance Project (RAP) and other commentators.

As highlighted in the previous section, as there is broad political agreement on the need for incentive based demand response and as it has been proven to be successful in the US, the main challenge to its growth in the EU appears to be two fold. Firstly, wholesale markets are currently designed to cater for large generation plant and secondly that the regulatory or market governance arrangements which shape such rules are shaped in a way which promotes the preservation of the status quo and/or does not promote demand side participation.

While the abovementioned new and/or draft network and market codes, and related EU reference models, being developed should improve the process, it is not yet clear how the situation will evolve. This uncertainty is increased by the very slow response of Member States to implement Article 15.8 of the EED.

Of the above stakeholders, the SEDC has published the most detailed analysis of the challenges faced by incentive based demand response providers and how these problems may be addressed. It has developed a set of regulatory requirements to enable Demand Response, which are structured around four main criteria:

1. Enabling consumer participation
2. Creating viable product requirements
3. Developing measurement and verification requirements
4. Ensuring fair payment and penalties

Firstly, as regards enabling customer participation, the SDEC notes that this would involve:

› Participation of demand-side resources in electricity markets should be authorised;

› Aggregated load should be allowed and encouraged to participate;

[49] Eurelectric, *Designing fair and equitable market rules for demand response aggregation*, March 2015.
[50] Smart Grid Task Force/EG3 Report, *Regulatory Recommendations for the Deployment of Flexibility*, January 2015.
[51] CEER, *Advice on Ensuring Market and Regulatory Arrangements help deliver Demand-Side Flexibility*, June 2014.

- Demand side competes on a level playing field.

With regards to the first two aspects, these are seen as necessary. The last aspect – a level playing field – *in SDEC's view* requires the introduction of a standardised framework which covers four main elements which allow the market to function reliably while allowing consumers to choose their aggregation:

- Volumes: Standardised processes for assessment of the traded energy between the BRP and the aggregator.
- Compensation: A price formula to calculate the price for the transferred energy. In the case of demand reduction, the aggregator pays the BRP; in the case of demand enhancement, the BRP pays the aggregator. This price formula should reflect as closely as possible the average sourcing costs of the energy transferred.
- Data exchange: A clear definition of what data needs to be exchanged between BRP and aggregator to ensure both can fulfil their obligations whilst not having to share commercially sensitive information.
- Governance structure: An appeals process and an appeals body, in case any issues need to be resolved.

It is interesting to note that while the SEDC propose both direct communication and compensation between the demand aggregator and the BRP, the practice in France is to avoid – in part for competition reasons – direct communications between both types of market participants; the practice in France is to work anonymously through a neutral demand response operator. Another important difference is that while the SEDC proposes that payments be paid on the basis of purchased energy, the practice in France is for payments to be based on regulated rates.

The second set of criteria relates to how specific market product requirements can impact demand response participation. The SDEC suggests that while genuine system constraints and security concerns must be respected, many different product/ programme participation requirements were historically designed around the specifics of generators. In line with the top half of the figure below (developed by demand aggregator company EnerNoc), it claims that rules on resource availability, event triggering, advanced notice, event duration and event limits favour generation companies.

Figure 3-3 Market design issues impacting incentive based demand response[52]

Thirdly, proper measurement and verification is essential for three aspects of demand response:

- To qualify potential resources against product specifications as an entry gate to participation
- To verify resource conformance to the product specifications during and after participation.
- To calculate the amount of product delivered by the resource as part of financial settlements.

This requires (i) baseline methodology metering configuration, (ii) product delivery, (iii) communication requirements, (iv) frequency of interval readings, (v) accuracy standards (vi) timeliness of measurement data and communication protocols. Essentially this involves three inputs. First, customer-specific dynamic baselines are required[53]. Secondly, the availability of smart or interval metering capable of regular two-way communication is also needed. Finally, the communications between the participant or his/her aggregator and the market is also required.

In line with best practice in the US, none of these issues should in theory pose a problem. Dynamic baselines have been developed for customers in a range of US regions, smart metering has been rolled out to almost a third of customers while

[52] Smart Energy Demand Coalition (SEDC), *Mapping demand response in Europe today*, September 2015.

[53] See the following for more information on baselines: http://www.enernoc.com/our-resources/white-papers/the-demand-response-baseline

communications between small as well as large wholesale market participants have been facilitated at least cost. That said, the level of controversy generated in the USA on incentive based energy demand response would suggest that care is needed in designing participation rules.

Finally, the regime for payments and penalties should be fair and transparent. This comprise three aspects:

› The market should be transparent so that generation and demand are rewarded in an equitable manner. This relates primarily to the level of information on Payment criteria, volumes and values provided by the market operator

› The market structures should reward and maximise flexibility and capacity in a manner that provides investment stability. While the demand side industry (SEDC) does not come down in favour or against long term capacity markets, it does state that flexibility and capacity should be rewarded. It also notes that services provided should be at market clearing (rather than at pay as bid)

› Penalties for non-compliance should be fair and should not favour one resource over the other. The question is whether the penalty should be scaled to the size of the nondelivered energy/capacity bid, which the demand industry advocates.

The SEDC assessed 14 established EU and two non-EU electricity markets and ranked them in accordance with the above criteria. The judgement criteria are described in the box below.

Text box 3-4 SEDC typology and metrics with regards to barriers to incentive based demand response

Score	Consumer Access and Aggregation	Programme Description and Requirements	Measurement and Verification	Finance and Penalties
5	Aggregated load is accepted in a range of markets, standardised arrangements between involved parties are in place – enabled through an independent third party	Programme requirements adjusted to enable a range of resources (supply and demand) to participate in multiple markets	Requirements are well defined, standardised, proportionate to customer capabilities, and dealt with at the aggregated level	Payment is fair and penalties are reasonable
3	Aggregated load is accepted only in limited number of markets, lack of standardised arrangements between involved parties	Minor barriers to demand-side participation in market remain, however participation is still possible	Requirements are under development, but do not act as a significant barrier	Payment is adequate, but unequal per MW between supply and demand; Penalty structures create risk issues for service providers, but participation is still possible
1	Aggregated load is accepted only in one or two programmes, lack of standardised arrangements between involved parties	Significant barriers remain, creating major competition issues for demand-side resource participation	Requirements act as a significant barrier to consumer participation	Payment structures seem inadequate, unequal pay per MW between supply and demand, penalty structures create high risk issues

Score	Consumer Access and Aggregation	Programme Description and Requirements	Measurement and Verification	Finance and Penalties
0	Load is not accepted as a resource in any market	Programme requirements block demand-side participation	There are no measurement and verification rules for Demand Response participation	Payment structure inadequate and non-transparent; penalty structures act as a critical barrier

In short, the SEDC's list of best practices would be based on:

- Aggregated load being accepted in a range of markets and standardised arrangements between involved parties put in place (enabled through an independent third party)
- Programme requirements are adjusted to enable a range of resources (supply and demand) to participate in multiple markets
- Requirements that are well defined, standardised, proportionate to customer capabilities, and dealt with at the aggregated level
- Payment is 'fair' and penalties are reasonable

Interestingly, beyond stating that demand response should be allowed to participate in for energy and capacity markets, the SEDC paper does not comment on what fair payment means. Indeed there is no consensus amongst its members as to whether the US based system of compensating collateral benefits should be replicated in the EU.

Their overall results by Member States are presented in the figure below.

Figure 3-4 SEDC assessment of performance of Member States with regards to incentive based demand response

2015					
	Consumer Access	Programme Requirements	Measurement & Verification	Finance & Penalties	Overall
Austria	1	3	3	3	10
Belgium	1	5	1	5	12
Denmark	1	1	3	3	8
Finland	1	3	3	5	12
France	5	3	5	3	★ 16
Germany	1	1	1	3	6
Great Britain	3	3	3	3	12
Ireland	3	3	1	5	12
Italy	0	1	1	1	3
Netherlands	1	3	3	3	10
Norway	1	3	1	5	10
Poland	1	1	1	1	4
Slovenia	1	1	1	3	6
Spain	0	1	0	1	2
Sweden	1	3	3	3	10
Switzerland	5	1	5	5	★ 16
Overall	26	36	35	52	149
Max score	80	80	80	80	320

As can be seen above, according to the SEDC, even those countries with the most favourable market rules in place do not score highly on all issues. Therefore this analysis would infer that market rules can be improved in all of the countries surveyed. Also, the paper notes that progress towards greater demand response cannot be assumed and that certain countries, in their opinion, such as Great Britain are at risk of taking a step back.

While there are some inconsistencies between the results of the previously described ACER questionnaire and the SEDC analysis, for the most the same Member States appear as forerunners in both. This includes Belgium, Ireland, France, UK and Finland, all of which have a need for new capacity, have significant flexibility challenges due to phasing out of nuclear and/or high RES penetration and so on. The main difference between the ACER study and the SEDC report is that the latter does not discuss how the demand response is provided e.g. through embedded generation, demand response etc.

As both of the above studies/reports focus on market rules, neither address regulatory barriers in any great detail. These are rather covered in other more policy oriented published by the CEER and the Smart Grids Task Force which recommend inter alia that:

- The roles and responsibilities of all involved actors (market participants, DSOs, TSOs etc.) should be clarified to be consistent with a level playing field.
- All relevant actors (ACER, NRAs, MS, EC, ENTSOs) should continue to ensure that the relevant network codes maintain a focus on promoting demand-side equally to supply and other flexibility measures (e.g. Demand Connection Code, Load Frequency Control and Reserves, and Electricity Balancing).

3.3 Problem definition and status quo analysis

The above sections outline the status quo of price and incentive based demand response across the EU, the main barriers to its growth as well as a number of good or best practices identified by the main stakeholders. The aim of this final part of Section 3 is to build on this background information to fully define the potential role of the European Union in tackling these barriers.

3.3.1 Problem definition

The problem definition, as well as identification of underlying drivers, is essential to any impact assessment as it presents the reasons why EU policy makers should or should not intervene, why action is required and why it should be the EU that takes it. The problem definition is used to inform the specific objectives and policy options put forward in the next section.

Presentation of the main problems

In line with the Better Regulation Guidelines, the definition of the problem is presented in five steps: (i) defining of problem and negative consequences, (ii) assessing the magnitude and EU dimension of the problem, (iii) outlining the underlying causes and drivers, (iv) identifying the stakeholders affected and (v) describing how the problem is likely to evolve with no new EU intervention. The table presents the draft outcome of these steps with regards to demand response.

Table 3-1 Identification and description of the problem

Issue	Demand response context
Defining the problem and its negative consequences	The EU's electricity sector needs more flexibility to enable it to accommodate the significant growth in variable/inflexible RES seen over the last 15 years and as well as in anticipation of the impact which electric vehicles (transport; 32% of EU energy demand) and heat pumps (heating and cooling; 50% of EU energy demand) will have on electricity consumption and peak demand growth in the next 30 years. The Commission notes that less than 10% of the EU demand response potential is utilised (SWD 2013, 442 Final). A number of barriers currently exist which make expanding beyond this 10% more difficult. Failure to do will result in greater curtailment of variable RES, missed targets, greater system management problems, and higher costs overall. In terms of alternatives, while demand response is the most immediately available and may actually be the cheapest flexibility option, other options include storage and better interconnection. That said, and although these can be substitutes for as well as complements for demand response, demand response appears to be the least cost option at least in the short and medium term during the period when these alternatives are not yet commercial. Either way, a failure to create flexibility will lead to significant curtailment of RES and/or increased generation and network costs.
Assessing the magnitude and EU dimension of the problem	Therefore, given the growth in variable RES on the system in the EU, in terms of system security and investment, it is likely that the need for flexibility services will grow and not diminish. As market power and price formation are linked to inflexibility, competition is also an issue. The question therefore is whether the growth in demand (and supply) flexibility which has been seen over recent years would be enough to cover such needs, and therefore negate the need for additional policy measures. Costs of duplication with other alternatives is also a consideration. Finally, the case for EU versus national action is weighed in favour of the former given the potential positive impact which incentive based demand response can have on the EU cross-border wholesale markets. The EU case for price based demand response is still there (e.g. allowing for customer choice), though it less convincing that action needs to be taken at EU rather than national level. The business as usual situation is described in the next section on Options.
Identifying the causes ('drivers') and assessing their relative importance	Within the context of highly regulated electricity markets, there are a number of technical, market and governance barriers to both price and incentive based demand response which can be addressed through public intervention. These are addressed in the next subsection on problem drivers.
Identifying the relevant stakeholders	The parties affected are those who bear the costs and benefits of the business-as- usual situation as well as any efforts to change it. This list includes Customers (industrial, commercial and domestic), network/system market operators (e.g. TSO and DSOs), national regulatory authorities (NRAs), existing electricity market participants (generators and supply companies), independent demand response providers such as demand aggregators as well as providers of smart metering and home automation services etc. Given the existing internal market rules, the types of stakeholder are expected to be broadly the same across the EU-28. The distributional impact may depend on the product involved with demand response in capacity programmes potentially resulting in higher market operation costs and demand response in energy programmes impacting vertically integrated companies. Overall, the distribution impacts will be assessed in the analysis of costs and benefits of the options which will be presented in the second intermediate report.

Issue	Demand response context
Describe how the problem is likely to evolve with no new EU intervention	In line with the terms of reference, smart metering, dynamic pricing and the removal of wholesale market and regulatory barriers may be needed to address these problems. With regards to smart metering, although the majority of customers will have these meters (72%) by 2020, it will not cover all (the other 28%) and some of those covered will lack the right level of functionality (circa 50% or less)[54]. This will reduce the demand reduction potential, at least for the next 15 years (the economic lifetime of such meters). Concerning dynamic pricing, a minority of customers – in particular domestic and SMEs – do not have access to dynamic tariffs which reflect underlying costs and hence do not response as they could. Therefore there is a lack of incentives to allow customers avail of the opportunities offered by smart meters. This situation may continue given low levels of competition at national level. Finally, in terms of wholesale market barriers, while the markets should continue to open up to demand side actors such as aggregators, it may do so at a suboptimal level and in a way which 'leaves' demand side participants outside of market structures or not able to access products which are tailored to generation plant, thereby leading to potentially discriminatory rules and additional costs for other market actors.

Identification of the underlying problem drivers

Even when a problem exists, it does not mean that public bodies should act. It depends in part on whether the problem is due to, or driven by, market and regulatory failures, in which case public intervention may be required. Specifically, a policy intervention may be justified when 1) a market fails; 2) regulation fails; 3) equity considerations imply the efficient outcome may not be the most desirable; 4) behaviours are biased and individuals do not decide based on their own best interests. The table below presents a selection of how these failures or considerations are relevant in the context of demand response, and what type of mitigation measure or response could be considered.

[54] European Commission, *Internal Note on Options for Retail Markets*, December 2015.

Table 3-2 Relevance of problem drivers, impact on form of demand response and potential mitigating action

Issue	Demand response context		Type of impact on demand response	Type of possible mitigation action
Market failures	*Public goods*	Public goods such as system security/ reliability are typically undervalued by the market and hence are often under supplied in the absence of intervention/regulation. One reason for this is that customers may not be compensated for the full system value of their individual demand response actions. TSOs and regulators intervene by setting system generation adequacy levels and procuring short term reserve capacity/ balancing and sometimes long term capacity. However, greater incentives on the demand side to provide such services can help address this somewhat by increasing the efficiency of the spot market (through energy bids) and through decreasing the cost of procuring reserves and balancing energy (through more competition for generation).	This problem primarily relates to the wholesale market and hence to incentive based demand response. If the demand side is not properly compensated it will not participate in the market.	Ensure that demand side response can both participate in the market (all parts subject to technical feasibility) and is properly remunerated. Examine options to provide demand side respondees not just benefit from bill reductions but also the collateral benefit they provide to other market participants. Provide that the demand response action is factored into the price setting mechanisms.
	Weak competition	The electricity sector is highly concentrated. Demand response can help strengthen competition by bringing more players into the market which decreases prices in particular during times when demand and supply are tight and significant price rises and spikes occur. It can also increase the responsiveness (or elasticity) of customers, which can help reduce market power.	This problem primarily relates to the wholesale market and hence to incentive based demand response. If demand response is discouraged, competition will have to be in the form of new electricity generation entrants or through regulation. The role of the demand side in checking market power is particularly important at times of system tightness/high peaks.	In addition to the above, actively ensure that demand response can be undertaken separately from other competing entities such as suppliers. Change regulatory incentives for network operators so that they promote and do not compete with DR. Provide that the demand side can participate in all wholesale markets.
	Imperfect / asymmetric information	Customers, who would otherwise respond, do not do so due to the fact that they lack the information on time-varying prices and capacity needs. Demand response measures, supported by smart metering and two way communication between wholesale market entities (suppliers, aggregators) as well as prices reflecting actual wholesale and network costs, can significantly help bridge this information divide and reduce transaction costs. This of course requires that such measures are cost effective!	As larger customers typically have a high level of awareness of their electricity usage – added by customised contracts and interval metering – this issue mostly concerns price based demand response by smaller customers.	Ensure that all customers who want it can receive, in a timely and economic manner, information on usage and prices; and that they can avail of least cost smart metering and other services to do so. Explore the possibility of also allowing suppliers and demand aggregators to provide smart meters or complementary devices (in addition to or instead of DSOs). (Care should of course be taken that such action does not lead to knock-on costs elsewhere)
	Split incentives	Electricity suppliers provide customers with advice on how to save energy. However, it is also in their interest to sell more energy against peak prices. This is particularly the case for integrated generation-supplier companies. The entry of independent	Both problems affect both price and incentive demand response as suppliers active in both wholesale and retail markets and TSOs and	As above with 'weak competition', ensure that demand response can be undertaken separately from competing entities. As regards network/market operators ensure that they are not just mandated but also incentivised to (at least not discouraged from)

Issue	Demand response context		Type of impact on demand response	Type of possible mitigation action
		demand service providers can provide an alternative to this relationship. In terms of network operators, while demand response may help avoid network investment, they are often incentivised through CAPEX arrangements to invest. This includes incentives to invest in smart metering.	DSOs impact the functioning of the wholesale and retail markets.	to promote and facilitate demand response
Regulatory failures	*Regulatory arrangements*	It could be argued that certain actors such as integrated incumbents and other participants may not face the right regulatory incentives to promote demand response. This in part overlaps with both the 'weak competition' and 'split incentives' market problems. As such they may argue for a preservation of the current regulations or rules/ status quo. Regulatory governance arrangements as well as tariff rules may be used to this end.	Both price and incentive based demand response.	Allow for equitable access for demand aggregators wo wholesale markets without need to contract directly with suppliers. This would involve offering new types of products to attract demand response. It would also require allowing the demand side to active influence governance arrangements. Regarding network operators, these can be incentivised to promote demand response through increased business or legal separation as well as through revenue controls Provide that customers can avail of real time prices based on underlying varying costs, even if not offered by suppliers.
	Poor implementati on of rules	It could be argued that the various actors responsible for market design and operation already possess the means to enable demand response. The issue therefore lies in its implementation by national authorities, regulators and system/market operators.	Both price and incentive based demand response but given the importance of wholesale market rules primarily the latter. While EU rules are already in place to promote DR, their lack of implementation at Member State level means that DR is not being properly facilitated and promoted.	Increase supervision and reporting on all aspects of demand response (such as that undertaken by FERC in US as regards monitoring, adherence with demand response 'orders' and publication of annual reports on demand response and smart meters).
	Out-of-date rules	Many of the enablers of demand response are relatively new. Therefore there is a question over whether or not electricity market rules reflect these developments or are geared to circumstances which were existing 10-15 years ago. These may have the effect of unnecessarily maintaining barriers to entry.	Both price and incentive based demand response but given the importance of wholesale market rules primarily the latter. Market rules needs to cater for demand side needs/specificities.	Linked to the 'regulatory arrangements' problem noted above, a regulatory review by each Member State could address this upfront and ongoing participation by demand side players in market governance arrangements should help ensure that rules remain up-to-date.
Equity considerations	There is a large size imbalance between electricity companies on the one hand who are quite large and energy service companies and consumers who are quite small. This means that the supply side companies, whose core activity is electricity, have the resources/means to participate in the market while demand side actors – who are less focussed on the electricity sector – face a number of barriers. One challenge is that different entities are not treated equally. In addition, even where they may be treated equally, the rules have been designed with large generation plant in mind and hence may not be equitable. There is also a divide between		Both price and incentive based demand response, but particular important for the latter. Rules made for existing large generation companies will discourage demand side players.	Again as noted above, simple equal treatment or a 'level playing field' may not be enough to encourage the participation of genuine demand response and not just distributed/embedded generation. There would be a need rather for the relevant tailoring of products to suit demand side so that participation is equitable (without of course discriminating against supply side actors).

Issue	Demand response context	Type of impact on demand response	Type of possible mitigation action
	commercial actors and regulated monopoly entities, whereby the later have considerable leeway in setting rules. In some cases the energy incumbent also own regulated monopoly entities, but is separated by business separation rules (e.g. DSOs and incumbent suppliers controlled by same board).	Rules that are not aligned with market costs (e.g. imbalance costs) could distort the market. Finally, small customers need to be provided with timely and accurate information	*There may also a need, where justified, for compensation mechanisms between actors for transfer of costs beyond their control (e.g. transfer of imbalance energy costs from aggregators to suppliers). Such a move may also possibly deter aggregators from increasing imbalances unnecessarily (moral hazard issue).* Finally, as discussed above under asymmetric information, given that smaller end customers are neither used to nor have the time to undertake detailed research on wholesale prices, there is a need to ensure that customers can access price and demand information in a timely and easy manner.
Consumer behaviour	Customers are used to being passive recipients of electricity and hence are not used to responding to price signals. However, the advent of smart metering and associated dynamic pricing means that customers now have more control. That said they may not want to do so where they see themselves as being exposed to prolonged wholesale market price spikes. At the other end of the spectrum, customers may be inactive despite it being in their best interest to change tariff/ alter demand patterns. The need here is to facilitate this control, allay risk aversion and counter inertia.	Mostly price-based demand response but partially incentive based DR (e.g. any automation).	While defaulting customers to real-time pricing and roll-out smart meters to all may be the most effective way to promote price-based demand response, it may be unpopular; a middle way may be required to help manage risk aversion/free-riding on the one hand and information asymmetries/ inertia on the other. It may be more feasible politically to ensure that customers with distributed generation could face real time prices In addition, as one can only expect so much load shifting to take place through deliberate action, measures to promote automated load control could be examined. Who aside from the customer would trigger such automation would have to be clarified.

In terms of the overall importance of the problem drivers listed above, it needs to be noted that all of the above problem drivers interact and cannot be seen in isolation. That said, given the success of price and incentive based demand response in the USA, it would appear that consumer behaviour and equity considerations are very important but not pivotal. Therefore, market and regulatory barriers appear to be of greatest relevance. In this regard, while market barriers are crucial, many of these could be addressed through regulatory measures. Therefore regulatory barriers may be the first priority area.

4 Definition of objectives and policy options

4.1 Introduction

In line with the ToR, the objective of this section is to build on the assessment of barriers, and possible best practices presented above to specify 'three progressive packages' of detailed policy options aimed at driving the deployment of both price- and incentive-based demand response.

As each of the proposed options will comprise of several different expected outcomes or measures, care will need to be taken to focus on those measures that are feasible and most relevant. In line with the Better Regulation Guidelines, the measures/options presented should be in line with specific objectives. Once a preferred option (e.g. option 2) or sub-option (e.g. option 2b) is proposed and discussed with the Commission, then the operational objectives can be outlined and assessed.

As outlined in the study's terms of reference, the outputs of the task will include detailed descriptions on the composition of the four options:

› Option 0: The business as usual – baseline scenario – that describes how the problem will develop with no change in current policy.
› Option 1: Demand response is promoted by legislation that gives all EU consumers access to dynamic pricing contracts.
› Option 2: Demand response is promoted by legislation that gives all EU consumers access to dynamic pricing contracts and standardised EU market rules for demand response service providers.
› Option 3: As Option 2 but where the demand response service provider has the right to offer its services without compensation to the retailer/BRP.

This involves three steps:

› A description of how the specific objectives link with the problems defined in the previous section;
› A draft definition of the policy options – e.g. what 'outcome' will be considered under each broad option, what could the measure look like

including assumptions to be made/considered? This will include an initial description of the BAU as well as of assumptions made and uncertainties posed;

- A more developed or screened list of options/ measures to be possibly brought forward for quantification in Task 3.

4.2 The general and specific objectives of demand response in the EU context

In line with Better Regulation Guidelines, once the problems and drivers have been identified, the next step is to outline the objectives which are to be focussed upon. As noted in the ToR, the general objectives in this area are ‘to improve the economic efficiency of electricity consumption in the context of increased intermittent generation and new energy technologies'. The terms also note that the aim is to ensure that all customers, including households, and their agents should be able to exploit the full potential of demand response and offer their flexibility to the market, on a voluntary basis and for a reward.

Beyond these general goals, the more specific objectives to be developed could potentially be to facilitate price-based and incentive-based demand response through:

1. the promotion of cost effective access by smart metering and related technologies
2. the substantial increase of availability and take-up of time varying, cost-reflective tariffs
3. the removal of regulatory and market wholesale market barriers to greater demand response in a sustainable and equitable manner.

4.2.1 Smart metering

The objective is to ensure that smart metering systems with the right functionalities and interoperability are available to consumers. Such systems are the key prerequisite for properly accounting for, and then rewarding, consumer's involvement in demand response or the use of distributed energy resources.

Specifically this means giving each consumer the right to request the installation (or upgrade) of smart meters with all 10 common minimum functionalities contained in the Commission's 2012 Recommendation at a cost to the consumer which is reasonable and cost-reflective (as verified by NRAs). Here the NRAs should also ensure a short waiting time for the installation.

While mandating the roll out in all 28 Member States by a certain date (e.g. 2025) with 10 recommended functionalities either for all consumers or for consumers above a certain consumption threshold is a possibility, we are of the view that such a mandatory approach could contradicts previous legislation, namely the IED of 2009 and the EED of 2012, and hence be dismissed.

This would mean that this option would consider a customer by customer 'roll-out'. It would need to be assumed or checked that the cost per customer would be higher given the lack of scale economies, perhaps increasing the per unit cost by up to 50 percent over the current €100 to €300 per metering point. As this may, however, have the effect of deterring customers from requesting smart meters, one additional objective could be to explore the need and feasibility of allowing competition (e.g. to demand aggregation companies, suppliers, ESCOs, others etc.) in metering for such customers (or allowing add-on devices). A key consideration here is to include the political feasibility of such a move (given the DSOs current role in this area in most Member States).

4.2.2 Time varying cost-reflective tariffs

Facilitated by the availability of smart metering, the main aim here is to help customers shift or reduce their peak demand in a way which helps postpone/avoid investment in the grids and in peak generation plant in the long term. Prices which reflect underlying varying (and fixed) costs will ensure that grid users are incentivised to behave efficiently and that accurate investment signals are transmitted throughout the network.

With regards to network tariffs this may involve a targeted EU intervention on distribution and transmission tariff structures to use time-dependent tariffs in order to promote and facilitate demand response, as well as complementary activities such as distributed energy resources and self-consumption.

Concerning end user supply tariffs, the aim is to ensure that consumers can obtain the right to a supply contract with dynamic prices, covering only access to real time prices as a minimum or to critical peak pricing and time of use tariffs as well.

Key considerations here concern (i) the proportionality of requiring suppliers – who are competing in an open market – to offer certain types of tariffs, (ii) whether it is possible to require that certain or all customers default to real time pricing, (iii) possible flanking measures to help reduce customer aversion to real time prices (e.g. caps, levelised bills) and (iv) the possible long term impacts on behind the meter storage/distributed RES.

4.2.3 Incentive based demand response in the wholesale markets

In addition to the abovementioned peak reduction investment benefits, incentive based demand reduction helps provide reliability services and improve price formation. In practical terms, this means helping avoid price spikes to enable the energy system to better cope with variable RES and new loads as well as to reduce the need for reliability related capacity investments. On the ground this would involve ensuring that market operators put in place suitable wholesale energy, reserves/balancing and where relevant capacity markets which provide equitable and tailored access to demand side resources.

In effect, this may mean establishing a market and regulatory framework that ensures that the demand side is facilitated by regulators and market operators as follows:

- a consumer has the right to choose an independent aggregator without the supplier's permission e.g. consumer can have two points-of-contact
- the market operator caters for the needs of the demand side e.g. through tailored participation rules including lower thresholds, fair access to equitably designed and tailored energy, reserves/balancing and where relevant, capacity markets
- entry, exit and trading rules are made in a neutral manner through representative and transparent governance arrangements e.g. the demand side can participate in wholesale market decision making; entry and exit is fast and low cost in terms of deposits etc.
- the roles, responsibilities and the liability of the different actors are fair and clear
- that the information flow among market actors and network operators is least cost and timely e.g. demand aggregators should not have to pay large sums to communicate with TSOs/DSOs; arrangements put in place should be proportionate/scalable to size of entity
- that, where needed, standardised contractual and compensation arrangements – including dispute resolution procedures - run by or under the supervision of the regulator are in place
- finally, that such information flow and contractual arrangements are in line with competition considerations

It may also require that demand side participants are incentivised via:

- prices which reflect the full value of their actions, including the social or collateral value if appropriate e.g. demand side bidding is rewarded for its impact on the market as a whole and not just by its own avoided costs
- the benefits are passed onto customers through clear application of customer protection rules to demand aggregators as well as to suppliers

4.2.4 Complementary/supporting actions/assumptions

As described in the previous sections demand response is also impacted by a number of factors which are outside the scope of this study such as rules on price regulation and network operator incentive mechanisms to name two. In this regard, in order to foster demand response, we are of the view that a number of complementary measures would nonetheless facilitate the achievement of the above objectives. These include:

- network costs recovered by tariffs (capacity-, demand- or energy throughput-based as appropriate) are genuinely those which relate to system costs and do not include costs which should ideally be collected through connection charges
- the role of distribution system operators needs to be defined more clearly and it acts in a neutral manner

- regulated prices have been phased out by 2020
- there is proper coordination[55] between distribution and transmission system operators as between them and the market operator
- network operators are obliged to and are incentivised to promote demand response (e.g. prioritise flexibility over reinforcement)

4.3 Definition of the options

Once the objectives and related potential measures have been identified and defined, the next step is to outline what is meant by each option. In other words, what measure would be considered under each option? The draft options and sub-options are presented below.

4.3.1 Option 0, business as usual (BAU)

While the assessment of any baseline option is usually relatively straightforward, there are a number of complications in the case of this study.

Firstly, the *status quo* in each Member State is very different with regards to both price-based (e.g. smart metering roll-out plans, availability and take-up of real time tariffs) and incentive-based demand response (e.g. wholesale market rules in place). For example, Italy is a leader in smart metering but suppliers do not offer time-varying tariffs to any great extent. Overall the picture is quite heterogeneous.

Second, the structure of the power sectors in each Member State varies considerably, which has a profound impact on demand response take-up. For example, while Denmark has a large penetration of variable wind generation, much of its balancing needs are met by interconnection from Norway providing hydro-electricity. Overall, the baselines will need to be defined for a variety of national situations.

Third, technological change in the sector renders making any prediction hazardous. While it may be relatively straightforward to assess the potential over the next five years, it will be almost certainly very difficult if almost impossible to say how things will look in 2030 given progress made on storage etc. Likewise it is difficult to see how distributed and transmission variable RES will progress. Such uncertainties need to be appropriately reflected in the analysis.

To take account of these and other considerations referred to above, it is proposed that this option could cover the following timelines and issues:

- For this and the other options below, two time horizons could be included:

[55] For more information on this issue, see http://fsr.eui.eu/News/All/EnergyClimate/SmartNet-Projects-kick-off-meeting.aspx

  - 2020 to cater for when most customers will have smart metering in place, time-varying tariffs in play and further growth of incentive based demand response in the wholesale markets; and
  - 2030 to cater for improvements to metering as well as innovation in areas such as behind the meter automation and storage, with the level of uncertainty for 2030 considerably higher.

  In all probability, while the 2020 predictions can be relatively conservative, two or more scenarios will have to be used for the 2030 figures, one optimistic in terms of technology and another not.

- In terms of underlying supply and demand conditions, existing European Commission modelled scenarios for 2030 should be used. Here it is important to gauge the increase in variable RES and its expected impact on residual load curves as well as likely impacts on demand and consumption of growth in heat pumps and electric vehicles. This would inform assumptions regarding the expected the expected knock-on effects of these changes on system imbalances and price volatility. Finally, assumptions on the development and penetration of behind the meter storage technologies and RES may have to be factored in as well.
- With regards to smart meters, by 2020 the BAU assumption is that 71% of customers and/or demand will have smart metering. For 2030, it is assumed that 74% of consumers have smart meters. However, it may be assumed that approximately half of customers would have the right functionality/access to visual information to allow for dynamic pricing.
- Concerning time varying tariffs, given the very low take up of such tariffs outside of Sweden and Finland, setting a reference penetration rate under the BAU will be more of an informed guess than an accurate estimate.

  For the purpose of the study, by 2020, it could be reasonable to assume that only very limited number of small customers (e.g. 5 percent) would avail of real-time pricing/critical peak pricing (even while another 30 percent or less availing of three part (peak, shoulder, off-peak) time of use tariffs supported by smart metering. In this scenario, the remainder would remain on flat tariffs.

  With regards to the possible response by those on time-varying tariffs, based on international experience outlined in the previous sections above, a conservative approach should be taken here to estimating average response capability (e.g. in the region of -0.1 price elasticity). It would have to be assumed that most consumption would be shifted to off-peak.

  Finally, the price differential for customers with dynamic pricing would need to reflect the underlying varying wholesale and network costs for that proportion of the bill that is variable. For TOU, a number of example rates would have to be tried and tested.

- With regards to incentive based demand response, we have assumed that the roll-out of the EU target model is slow, and framework conditions remain challenging in MS having implemented the target model already. Therefore it cannot be assumed that demand response will continue to grow, but rather stay at current levels. Variations of the BAU will have to be outlined, including how demand response will evolve with changes in key variables. Two of these include the existence of long term capacity markets (which has pushed incentive based demand response in the US) and rules which allow greater flexibility for non-distributed generation-driven incentive-based demand response.

4.3.2 Option 1, Demand Response (DR) is activated through granting consumers access to a smart meter and dynamic pricing contract

This option essentially involves <u>three types or groups of measures</u>:

(i) extending availability to smart metering to allow customers to respond (to price or other signals)

(ii) providing access to dynamic prices to all customers to provide incentives for price related demand response and

(iii) having these dynamic tariffs reflecting underlying system costs so that such incentives are adequate

(iv) We also assume some progress on implementing the EU target model and the implementation of Network Code on balancing for MS already having implemented the target model

As described above, the first main measure which would be expected is to (i) <u>ensure the availability of smart meters to customers on a request basis</u>. Again, this means that any customer would be allowed to request and receive an interoperable smart meter with minimum functionality at a reasonable cost. What this means in reality may have to be determined by the national regulator. Presumably while the specific customer and demand side management benefits may remain, the full benefits will not be reaped. This customer by customer approach may mean that the overall system-wide benefits, such as avoidance of fraud, may be lower. Likewise, due to a lack of economics of scale, the *per unit* costs may be higher. To be clear, it is our understanding that this option does not involve the reassessment of Member States' Cost Benefit Analyses undertaken in line with the 2009 IEM Directive.

Nevertheless, a number of unanswered questions remain. For example, what type of meter could be offered to customers is an open issue. Would it be possible to allow customers to buy their own meter? How would telecoms be handled? It may be preferable in these cases if the metering market was open to competition. However, this issue goes beyond the scope of this study.

The second main measure which would be expected would be to <u>require suppliers to offer dynamic tariffs through rules on customer contracts</u>. What could be done here is more complex than in the case of smart metering. For example, there are a range of sub-options which could possibly be considered:

› <u>Time of use pricing (TOU)</u>: Prices are set in advance to reflect underlying changes in seasonal and diurnal (e.g. daily) electricity costs but do not reflect underlying dynamic prices at any given time. Experience from jurisdictions with TOU is that there would be a need for three, rather than two, time periods to truly avoid simply shifting the 'peak around'.

› <u>Critical peak pricing (CPP)</u>: Similar to TOU above but with the difference that peak prices can vary in line with system conditions. How the 'peak' time interval changes depends on how the pricing intervals are set (i.e. peak time periods need to be very limited in duration e.g. maximum two hours per day) and the number of peak periods may have to be limited to 10-15 days a year.

- Real time pricing (RTP): Basically, this is the situation where prices reflect wholesale markets but with some additional 'retail' features such as price caps and floors etc.

In line with the terms of reference, one of the main aims of the EU in pushing for greater demand response is to accommodate variable and unpredictable RES. As it is much more difficult to predict when a peak period will occur, *ex ante* TOU tariffs may not be fit for purpose. Therefore, to be effective, there may need to be more focus on more dynamic CPP and RTP which reflect underling market conditions than static TOU.

Another issue is whether such tariffs would be the default situation or whether customers would have to 'opt in'. Our assumption here is that, as with smart metering, for the majority of final customers, such pricing would be done on an 'opt-in' basis but that willing customers would have access or the ability to opt in to cost reflective dynamic tariffs. However, given the impact of customers with distributed generation on the system, this option could qualitatively examine the impact of applying RTP to these customers.

Yet another issue is how the visibility of their demand and the prices they face affects price based demand response. It is expected that a large majority (81%) of customers will have smart meters by 2030, while a much smaller proportion of these customers will take up tariffs that allow for price based response to materialise.

Another issue – which is not an outcome as such – is the impact which continued end-user price regulation could have on the feasibility of dynamic pricing. While TOU pricing and pricing regulation can easily co-exist, price regulation based more on dynamic prices – such as CPP and RTP – may not be feasible. In short, this is because price regulation dulls wholesale market signals and prevents the take-up of such pricing arrangements.

Many customers may not wish to face wholesale market changes and may wish to be protected from severe price hikes which could be possible under RTP. Indeed, many customers may not even want to be on TOU tariffs as this would be seen as exposing them to possible bill variations. In this regard, it is important not to confuse the price signals customers face and their payment arrangements. For example, customers could at the same time face real-time prices but pay bills which are 'levelised' across the year. Linked to this is the effect which price regulation and RTP can have on customer switching – without the right safeguards, customers may choose to switch away from RTP during winter or during periods where underlying wholesale market prices surge (e.g. such as during prolonged droughts).

Many of these issues may be difficult to push in an independent market where suppliers should in theory be free to set their own tariffs and therefore should already be offering such prices themselves without the need for intervention by policy-makers.

Finally, the reality on the ground is that a very small minority of customers face real time prices in the EU, and these are primarily situated in Sweden and Finland.

Therefore, even RTP was made available to all, there may be a limited take up of RTP (e.g. to 20 at best under an 'opt-in' system and 50% under an 'opt-out' system).

The third and last most important issue for encouraging price-based demand response is to ensure that tariff structures sufficiently reflect underlying time varying costs. This means that end user tariffs should include not just energy market prices variations but also variations in network (transmission, higher end distribution) costs. On the ground in the EU, there are large differences with some countries charging network costs on a predominantly flat kWh basis (e.g. Ireland) while others charge on a KW (Netherlands). As changing tariffs is, at least in the short term, a zero sum game, making such changes may not be politically popular.

The implementation of the EU target model will give large consumers access to the wholesale energy markets and will open the possibility to adjust demand bids to the price level in the DA markets. This will provide some DR. For markets having implemented the target model, we do not see any adjustments in the requirements for demand side participation, and due to this there is no increase in demand participations outside of the energy markets.

4.3.3 Option 2: Activating price- and incentive-based DR happens through access to a smart meter/dynamic pricing contract & through standardised EU market rules for demand response service providers

While Option 2 builds on the price-based demand response measures included in Option 1, in many respects it is quite different. For example, while Option 1 is primarily concerned with smaller customers (e.g. domestics and SMEs) who do not have interval metering, Option 2's aim to promote incentive-based DR is more focussed – at least in the short-term – on larger customers who can participate in the wholesale market through demand aggregators and who already have interval metering and should or could have dynamic tariffs. In addition, not having to wait for smart metering and dynamic tariffs also means that the potential for quantity based demand response may be greater in the immediate term.

With regards to how price- and incentive-based DR will interact, one view – held by SEDC – is that they should be seen as complements and not as substitutes. For example, it is theoretically possible that a medium- to large-customer can avail of real time prices and bid into the wholesale market at the same time (e.g. and therefore be compensated twice, once in terms of the avoided private costs through not consuming and a second time through compensation for lowering 'social/ system/ collateral' costs for everyone else). However, this may not be desirable if it leads to claims of over-compensation. Another view – held by Brattle to a certain degree – is that price and incentive based DR can be substitutes. For example, success in meeting the potential of demand response in the wholesale market may dull any real time price signals in the retail market and vice versa. These complementary and substitution effects need to be covered and hence Option 2 cannot be seen as a simple add-on to Option 1. A final consideration is that while incentive based DR may lead to more attainable results in the short term (e.g.

2020), pushed by greater automated control and storage options, price based demand response may gather momentum later towards 2030.

With regards Options 2 and 3, in reality they are for all intents and purposes alike except for the fact that under the former demand aggregators are required to compensate suppliers for imbalances caused while in latter they will not.

Table 4-1 Possible sub-options to consider for incentive-based demand response

	Consumer Access and Aggregation	**Programme Description and Requirements**	**Finance and Penalties**
Option 2	Demand side competes on a level playing field (aggregation and adaptation of rules) Standard settlement and compensation processes between BRP and aggregators.	Adapted to reflect needs of demand side (e.g. longer notification times, shorter bid or balancing windows etc.)	Level playing field for demand and generation
Option 3	Same as Option 2 except that there are no settlement between BRP and aggregator and no compensation paid	Adapted to reflect needs of demand side, same as option 2	Aggregators holding no balancing risk and do not compensate for imbalances

There are two assumptions that included in both options:

- measurement and verification systems and procedures in place
- information on demand side position provided through independent middleman (e.g. TSO or market operator)

Option 2covers a situation where market rules are changed to accommodate demand side resources. In detail this means making changes to allow genuine demand response to participate and hence reduce the proportion of demand response accounted for by distributed generation when the demand side provides flexibility at a lower cost. The assumption here is that such changes would also require the removal of regulatory barriers which prevent market rules from changing. Another issue is how demand response is communicated to suppliers. This can either be directly from the demand aggregator to suppliers – which may raise competition issues – or indirectly through a hub operated by an independent operator.

While there are many individual measures which can be taken, and although some are more important than others, it would be difficult to identify the individual result of changing each and every barrier. Therefore this option will group the removal of all the technical barriers together.

4.3.4 Option 3: Activating price- and incentive-based DR happens through access to a smart meter/dynamic pricing contract and the right of DR Service providers to offer their services without compensation to the retailer

With regards to demand response in the balancing energy markets, all of the above are based on demand side participants – including but not limited to demand aggregators – being subject to balance responsible party obligations. This fourth sub-option would depart from this by removing this obligation from these participants.

As highlighted in the section above, the electricity market models in place in the vast majority of EU Member States – and indeed the expected EU market model – are decentralised self-dispatch models. Contrary to a centralised TSO-dispatched model, the rule in Europe is for participants to be responsible and hence pay for their own imbalances. One the one hand, the TSO wants to discourage imbalances and hence balancing prices can carry a heavy premium and on the other this deterrent may need to increase in future years as RES increases the level of imbalances on the system. Failure to provide such a deterrent can also have knock on effects on the day ahead and intra-day markets.

As the issue will most probably increase and not decrease in significance the question is rather who should pay for these imbalances and how these imbalances could be reduced in the absence of compensation.

5 Impact of policy options

5.1 Introduction

The section describes the assessment of the policy options including the business as usual scenario (also referred to as the 'baseline scenario'). The section includes approach, assessments and results. The section is structured as follows:

- Identification of a theoretical demand response potential (Section 5.2)
- Defining the approach to quantification for price based and incentive based DR
  - Approach to price based demand response (Section 5.3)
  - Approach to incentive based demand response (Section 5.4)
- Assessment of the policy options including baseline: Estimation of how much of the technical demand response potential will be activated under each policy option
  - BAU (Section 5.5)
  - Option 1(Section 5.6)
  - Option 2(Section 5.7)
  - Option 3(Section 5.8)
  - Summary of the effects of all four options (Section 5.9)
- Cost and benefits of the policy options (Section 5.10)

It means that in Section 5.2, a theoretical demand potential is estimated. It covers a number of consumption elements for industrial, commercial and residential consumers. The activation of the demand potential depends on the policy option and the mechanism – price or incentive based activation.

The approach to assessing how much of the theoretical demand response that is activated under price and incentive based mechanism area presented in the following two sections. Section 5.3 presents the approach to estimating the level of price based demand response. The section also includes an estimate of the current level of prince based demand response.

Section 5.4 comprise similarly a description of the approach assess incentive based demand response activation and a sub-section on the actual level of incentive based demand response.

Section 5.5 to Section 5.8 then applies the approach to provide the estimates of price and incentive based demand response under the BAU and the three policy options.

Section 5.9 includes the estimation of the costs and benefits of the BAU and the policy options. The costa are the activation costs and the benefits are estimated as the reduction in generation and transmission/distribution costs resulting the effect of demand response in the peak demand.

5.2 Identification of the demand response potential

Based on a literature review, the possible approaches to estimate demand response potential have been considered. Some studies present demand response as a percentage of the peak demand while others have based the assessment on a breakdowns of electricity consumption by consumer type and appliances/processes. We chose an approach that evaluated the potential per consumption type and consumer type in order to compile an estimate of technical depend response potential.

5.2.1 Definition theoretical demand response

The work of Gils (Gils 2014, Gils 2015)[56] was the most comprehensive assessments of the theoretical demand response potentials that was identified. In his article, Gils distinguishes between the theoretical, technical, economic and practical potential of demand response:

- **Theoretical potential** includes all facilities and devices of the consumers suitable for demand response.
- **Technical potential** includes only the facilities and devices that can be controlled by the existing information and communication infrastructure.
- **Economic potential** is the part of the technical potential that can be operated in a cost-efficient way.

Practical potential is the part of the economic potential that is accepted by users. This is the potential that can be deployed for actual demand response. Gils' work provides the most comprehensive insight in the theoretical potential of demand response. The data cover a detail breakdown by consumer type (industrial, commercial and residential), appliances/process and by Member State. Moreover, the data set includes estimates for 2020 and 2030. These data that were used as input for the journal article and the dissertation thesis are publicly available and

---

[56] Gils, Hans Christian (2015) *Balancing of Intermittent Renewable Power Generation by Demand Response and Thermal Energy Storage*, Thesis for Doctor of Engineering Sciences Degree, University of Stuttgart, 2015
Gils, H.C. (2014) *Assessment of the theoretical demand response potential in Europ*e, Energy 67 (2014)

have been used as the main source to determine the potential of demand response. Other studies[57] included assessment of similar consumption types but only for one country. The other reviewed have estimated similar levels of demand response given that they also take into account the limiting factors.

The data of Gils is only focussed on the theoretical potential of demand response. However, in this study, the focus is on the technical potential of demand response. Therefore, limiting factors, such as ICT, cost or acceptance of demand response are part of the assessment. Hence, this theoretical potential provides the basis for estimating the technical potential of demand response under the alternative policy options, which are calculated according to the methodology discussed in Section 5. 3 and 5.4.

5.2.2 Analysis

This paragraph explains the methodology Gils applied to determine the theoretical demand response potential.

Four steps were taken to compile the data. First, the processes and appliances suitable for demand response were identified. In order to analyse the variability of demand response potential during the year, a load profile was added per appliance or process. No new load measurements were taken; therefore, the load profile was based on literature or available data. Subsequently, annual electricity demand, installed capacity and a flexible load share for each consumer was evaluated. Thereafter, the geographical distribution of demand response potentials was evaluated. Finally, the expected growth was considered from 2010 to 2020 and 2030.

Appliances and processes suitable for demand response

Thirty-two different processes and appliances were identified for demand response[58]. Each have one of the following characteristics: heat or cold storage, demand flexibility or physical storage. These different processes and appliances lead to different types of demand flexibility. This can be seen in for example time a load can be shifted. The loads of processes and appliances are divided into different

[57] For example:
Frontier Economics (2015) *Future potential for DSR in GB*, London October 2015
Fraunhofer ISI and Forschungsgesellschaft für Energiewirtschaft (2014) *Load Management as a Way of Covering Peak Demand in Southern Germany* Agora Energiewende May 2014
VDE-Studie (2012) *Demand Side Integration Lastverschiebungspotenziale in Deutschland*

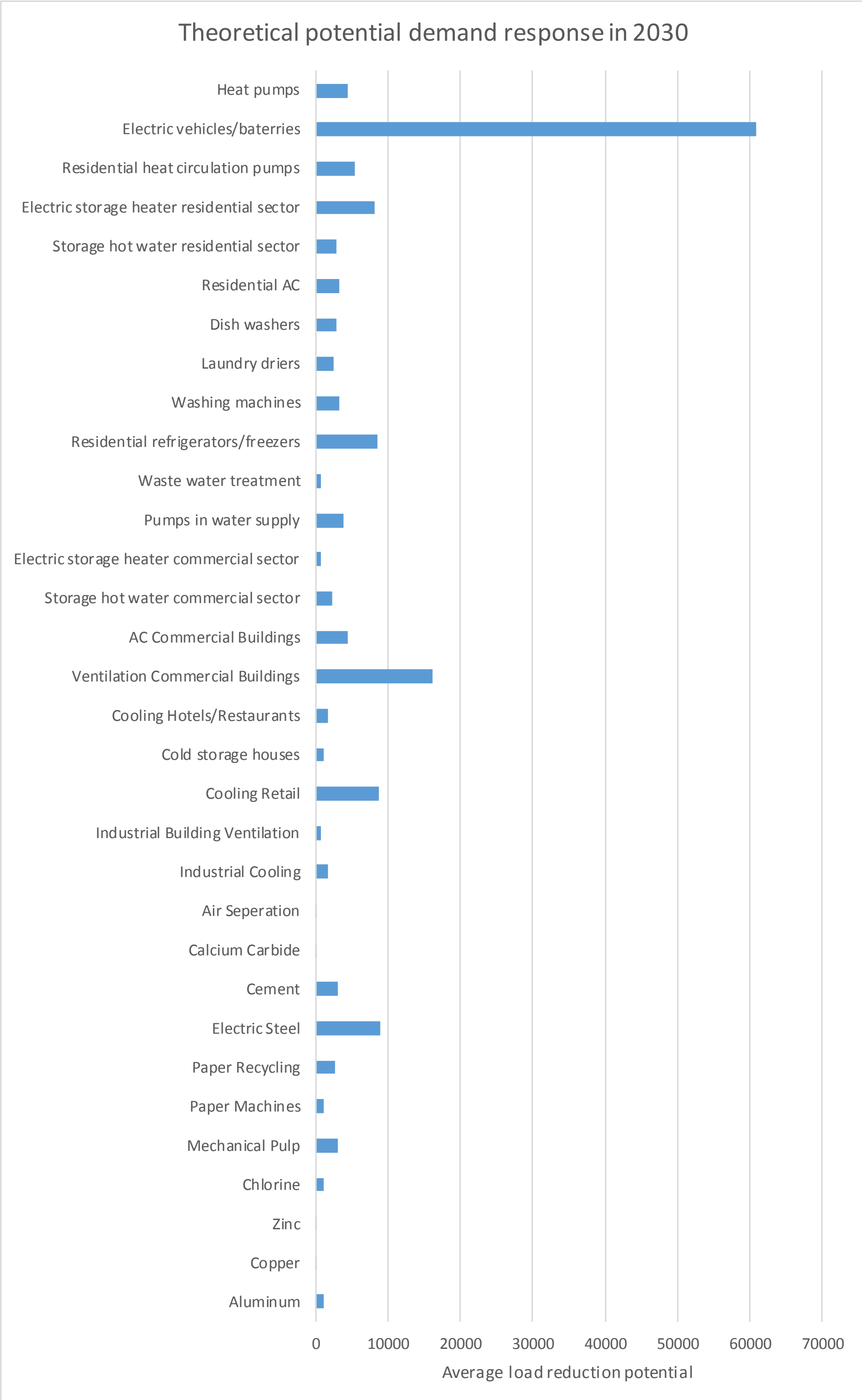
[58] The load reduction potentials of heat pumps (HP) and electric vehicles (EV) are not estimated in the same manner as the other 30 processes. Gils provides estimates of expected energy consumption from HPs and EVs in 2020 and 2030. Using average capacities of EV batteries, average charge times of batteries and average operating hours for HPs the energy consumption is converted to average load. I addition, HPs and EVs constitute highly flexible demand which lends itself easily to demand response. Hence the DR potential of EVs and HPs is assumed to be very high (25% of load from HPs and 50% of load from EVs)

consumers types (industrial, commercial or residential). In Figure 5-1 the theoretical potential of demand response is visualized for all the appliances that are evaluated.

Based on available information on the flexible loads of processes and appliances over time, Gils estimated the possible load decrease and increase for each hour of the year. The analysis comprises different consumer sectors and countries. The overall potential of demand response varies during the year. For this reason, Gils has defined a maximum, minimum and average increase and a maximum, minimum and average reduction of power (kW). In this report, only the average reduction is taken into account as an indication of what peak load reduction is possible. Hence, the increase of minimum load is not considered. In Figure 5-1 an overview of the total theoretical potential of demand response is provided per appliance for 2010, 2020 and 2030. The total theoretical potential is the sum of the theoretical potential of all countries that are evaluated. The countries that are evaluated are listed in Figure 5-2.

The potential load reduction of energy intensive industry in each hour is given by the difference between the actual load and the minimum load. For the cross-sectional cooling and ventilation the potential is based on the installed capacity. In the assessment of potential load reduction, fixed shares in current load reduction and unused capacity increase, available for DR are assumed. The residential potential is defined with a bottom-up approach in which the number of households and country specific equipment rates are taken into account.

Figure 5-1 Theoretical demand response potential per type of appliance or process in MW

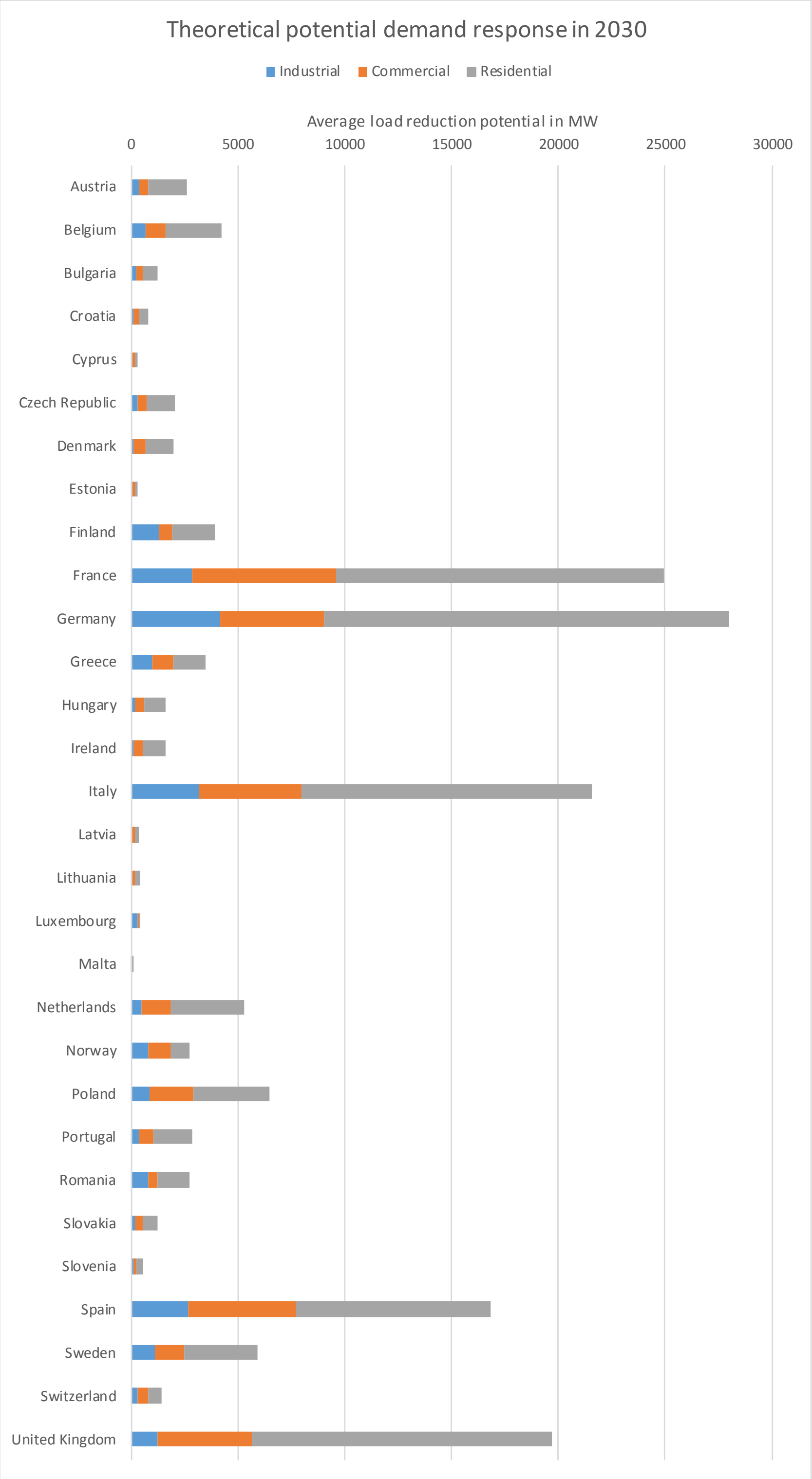


Source: Gils (2014)

Figure 5-1 shows a relative high theoretical potential for ventilation of commercial sector. It is also clear that the theoretical demand response of industry is mainly related to an increase of flexible loads in electric steel makings. In the residential sector mainly freezers and refrigerators, and the electric heater with storage capacity show a high theoretical potential.

In Figure 5-2 the theoretical demand response potential per country is provided. The potential is divided into industrial, commercial and residential potential. The high potential of Germany and France is additional to the installed capacity of flexible loads, also a result of the relatively high population density.

Figure 5-2 Theoretical demand response potential per Member State in MW



Source: Gils (2014)

The total theoretical potential as estimated in Gils (2014) are presented in the table.

Table 5-1 Estimated demand response potential in MW

	Total theoretical demand response potential in MW
2010	95,700
2020	120,800
2030	160,900

Source: Gils (2014) and own calculations

The main driver of the growth in the theoretical demand response potential for 2020 and 2030 is the development in energy consumption from Heat Pumps (HPs) and Electric Vehicles (EVs). From 2020 to 2030 energy consumption from EVs is expected to triple and from HPs is expected to double[59]. A large share of the average load from HPs (25%) and EVs (50%) is expected to be suitable for demand response. As a result, the growth in HP and EV energy consumption play an increasingly large role in the total demand response potential.

5.2.3 Cost of activation

Studies on the cost of activation of demand response typically approach this subject from a market or network perspective at the supply side. Cost of activation is thereby understood as the monetary incentive needed to induce an operator's or customer's willingness to react and adapt. However, from a cost point of view, a look at the necessary components, opportunity costs and value of lost load is needed at the demand side.

Components that are needed to make an installation smart and compatible with demand response are most importantly connected control units and the associated information infrastructure.[60]

One study divides the costs of demand response into the three categories investments, fixed costs and variable costs.[61] Investments must be made for acquisition and set-up of the components. Components that are needed to make an installation smart and compatible with demand response are most importantly connected control units and the associated information infrastructure.[62] Industrial applications are usually equipped with these necessary components and infrastructure. Accordingly, investments can be negligible. For residential consumers these investments are much higher because of the number of units that must be controlled. Fixed costs may occur for information or transactions. These are also negligible in most cases. In the event of a performance reduction of the responding installation, variable costs may occur in the form of additional maintenance or fuel costs. In the case of battery based storage as provider of

[59] Gils, Annex E3
[60] cf. smart metering
[61] Kreuder, Quantifying the Costs of Demand Response for Industrial Businesses, 2013.
[62] cf. smart metering

demand response a higher number of charging cycles reduces the installation's life expectancy and therefore causes damage that must be included in the costs of providing this flexibility.

Gils also mentions storage costs and opportunity costs. The study concludes that demand response in the industrial sector break even at €434/MWh.

A survey among companies in the Finnish metal, chemical as well as pulp and paper industries has been carried out by the Technical Research Centre of Finland.[63] Industrial processes for the production of pulp and paper are able to provide demand response with a duration of up to 3 hours without any notice time. Processes in the metal industry are more manifold and may require a notice time between 0 and 24 hours in advance to the demand response. Response duration can exceed 12 hours. As for the chemical industry response duration lies mainly between 3 and 6 hours with necessary notice time between 0 and 24 hours. Another article based on a survey among industrials in Germany assumes a range of €30 to €500 per MWh demand response.[64]

An extensive literature review on demand response was carried out in another study on the financial impact of demand response.[65] The authors state different durations of potential load shifts through demand response per consumption class other than industrial processes. While applications such as cooling or ventilation may not be postponed for more than 1 hour, rather discrete applications such as laundry can be shifted for a full day.

Table 5-2 summarizes findings on the duration, delay and costs of activation of demand response for each consumption type.

Table 5-2 Duration, delay and cost of activation per consumption type

Consumption type	Consumption class	Shift duration (h)	Notice time (h)	Cost of activation (€/MWh)
Aluminium	Process Technology	12	2	225
Copper	Process Technology	12	2	225
Zinc	Process Technology	12	2	225
Chlorine	Process Technology	6	1	225
Mechanical Pulp	Process Technology	3	0	225
Paper Machines	Process Technology	3	0	225
Paper Recycling	Process Technology	3	0	225
Electric Steel	Process Technology	12	2	225
Cement	Process Technology	6	1	225
Calcium Carbide	Process Technology	6	1	225
Air Separation	Process Technology	6	1	225
Industrial Cooling	Air conditioning	1	0	70
Industrial Building Ventilation	Ventilation	1	0	70
Cooling Retail	Cooling	1	0	70

[63] Pihala, *Demand Response Potential Assessment in Finnish Large-Scale Industry*, 2005.
[64] Klobasa, *Analysis of demand response and wind integration in Germany's electricity market*, 2010.
[65] Feuerriegel, *Measuring the financial impact of demand response for electricity retailers*, 2013.

Consumption type	Consumption class	Shift duration (h)	Notice time (h)	Cost of activation (€/MWh)
Cold storage houses	Cooling	1	0	70
Cooling Hotels/Restaurants	Cooling	1	0	70
Ventilation Commercial Buildings	Ventilation	1	0	70
AC Commercial Buildings	Air conditioning	1	0	70
Storage hot water commercial sector	Thermal energy storage	12	0	55
Electric storage heater commercial sector	Thermal energy storage	12	0	55
Pumps in water supply	Process Technology	6	1	225
Waste water treatment	Process Technology	6	1	225
Residential refrigerators/freezers	Cooling	1	0	70
Washing machines	Laundry	24	0	10
Laundry driers	Drying	24	0	10
Dish washers	Washer	24	0	10
Residential AC	Air conditioning	1	0	70
Storage hot water residential sector	Thermal energy storage	12	0	55
Electric storage heater residential sector	Thermal energy storage	12	0	55
Residential heat circulation pumps	Heating	12	0	10
Electric vehicles/batteries	Batteries	3	0	10
Heat pumps	Batteries	3	0	10

Source: Kreuder (2013), Feuerriegel (2013), Klobasa (2010), Pihala (2005) and own calculations

The assessment of the shift duration and activation costs is used to estimate the benefits of demand response in Section 5.10. The data also feed into the demand curves described in Section 6.

5.2.4 Cost of smart meter installation

The roll out of smart meters are also a precondition for realising the demand response. In most Member States, the roll out has been planned or is being implanted already. Based on the cost-benefit analyses (CBAs), Member States have decided on the roll out. The CBAs have shown that there are many benefits of smart meters and therefore not all the costs should be included this assessment. For the Member States that have decided on full-scale smart meter roll out, no costs are included in the BAU. For the assessment of the options where additional meters might be installed, the following assumptions are applied. The costs per meter point is based on the average costs for the Member States where additional meters might be installed. The costs is 279 EUR per meter point[66]. It is then assumed that half of this cost is attributed to other benefits (for example lower costs of meter readings). The meter cost is then annualised assuming a lifetime of 15 years.

[66] Calculated based on data from the CBAs, see AF Mercados EMI and NTUA, *Study on cost benefit analysis of Smart Metering Systems in EU Member States, Final Report*, 2015.

5.3 Price based demand response

The previous section has considered the theoretical demand response potential available across EU Member States. This section estimates price-based DR building upon this theoretical potential and other data for the following periods:

- Current price-based DR (2016)
- Future periods – namely 2020 and 2030 based on a business-as-usual scenario
- The same future periods of 2020 and 2030 under Policy Option 1.

Previous sections of this report have defined price based demand response as the capacity of customers to response to price signals which reflect underlying and varying costs. The forms of price based DR of most interest for this analysis are the use of 2-, 3- or more part time-of-use (ToU) tariffs that fundamentally reflect the cost of supply, real time pricing (RTP) and critical peak pricing (CPP). While there are several examples of traditional ToU tariffs (day/night tariffs etc.,) that are associated with load shifting, these are of less interest for policy purposes as it is unclear that they have strong economic rationale.

This section estimates price-based DR across the EU-28 for the various periods by considering a number of critical variables:

- The potential load that is conducive to shifts when customers receive appropriate price signals.
- The spread of smart metering systems and in particular the spread of smart meters with appropriate functionality for price based DR including 2-way communication with the service provider.
- Customer take up of new forms of ToU pricing, RTP and dynamic tariffs.
- Changes in customer demand patterns where they are subject to new forms of pricing.

5.3.1 Existing price based DR

Section 3.2.2 has outlined that the vast majority of EU customers have access to tariffs that vary to some extent by time. These tariffs are distinguished by only requiring basic metering technology, and by not necessarily reflect underlying network or retail supply costs. Time based tariffs were typically introduced in the 1970’s or 80’s for customers with significant off-peak uses of electricity, including space heating and hot water storage, with an important distinction between day and night uses.

Despite the long history of two-part tariffs there is only fragmentary evidence of the amount of demand that has actually been shifted from peak to off-peak periods in MS. This is not unsurprising as it is difficult to effectively estimate the impact of two-part pricing due to:

- The lack of a clear counterfactual,
- The possibility of self-selection bias – that is customers with greater demand in off-peak periods are those who choose the 2-part tariff,
- The tying in of ToU tariffs with other forms of load control (e.g., pre-setting heating appliances by utilities),
- Limited studies undertaken by utilities, and general difficulties in performing empirical studies of simple ToU tariffs. Torriti (2015) notes that a problem with econometric analysis considering price variables is that the only statistically significant predictor of consumption is past consumption[67], and
- The relatively raw nature of the metering data.

In practice, the extent to which load been shifted depends upon:

- The amount of customers who take up two- or multi-part tariffs,
- The price differentials between peak and off-peak, and how these relate to fixed price tariffs on offer; the greater the difference between the single part tariff and the peak rate of a 2-part tariff, the greater the risk of paying more on the 2-part tariff; while at the same time the greater reduction on offer in the off-peak period will provide stronger benefits to shifting load to off-peak periods, and
- The availability of appliances conducive to load shifting based under simple (traditional) metering technology.

Traditional two-part tariffs are not necessarily efficient. These tariffs are generally fixed well in advance, without any reflection of the actual situation in the market, meaning that it may be a fortunate coincidence when the tariff reflects the underlying wholesale or network costs. Reflecting this weakness, more market-based TOU tariffs are being offered in some MS consistent with the spread of more advanced metering technology. A summary of the status of price based approaches by MS – including both traditional and market-based ToU tariffs - is set out in the table below.

[67] Torriti, Peak Energy Demand and Demand Side Response, 2015, p.84.

Table 3 Status of Price based DR in MS

Member	Spot prices (Real time)	CPP	TOU	Comments
Austria	X		X	EVU offers TOU, specifically Day-and Night tariffs[68].
Belgium	X		X	Peak, off-peak and real time tariffs are offered, though smart metering uptake is limited.
Bulgaria				No reported price-based DR. According to the Bulgarian NEEAP, dynamic tariffs will be introduced in the future.
Croatia			X	No price-based DR reported.
Cyprus			X	TOU tariffs are theoretical available for domestic, commercial and industrial customers. Not for public light or water pumping customers.[69] Market conditions for DR not considered applicable.
Czech Republic			X	TOU tariffs are combined with load control, with space heating and water heating restricted to off-peak periods with lower tariffs. The DR can be seen as more administratively determined than price based. However, the Ministry will be introducing new tariffs, which relax the control arrangements, allowing customers to optimise behaviour[70].
Denmark			X	ToU is available for customers with hourly metering, and mandatory for those customers connected to grid with a voltage level of 10 kV or higher[71]. Focus is on future enabling price-based DR through smart meter rollout and dynamic tariffs.
Estonia	X		X	Off-peak tariffs and real time tariffs are available. However, limited motivation to participate in DSR schemes reported.[72]
Finland	X		X	TOU are commonly used and are combined with smart meters. They are offered to all customers and they are mandatory for large customers.[73]
France		X	X	System of ToU tariffs in place for more than 40 years. Selection of available tariff schemes (peak and off-peak, Tempo tariff (CPP tariff)).
Germany	X		X	Mostly Peak (day hours) and Off-peak tariff (night hours) – system considered in need of redesign, given increase of RE in the energy mix. Consumers > 10 GWh receive tariff discount for maintaining a flat load profile.
Greece			X	ToU tariff available. Impact unclear
Hungary			X	ToU available: In addition, "ripple control" provided for some loads.[74] Load shifting more control- than price- based.
Ireland			X	ToU tariffs offered, with different load profile for those on the tariff reported. However, unclear the extent to which price has influenced the shift.
Italy			X	Full smart meter roll out and on-peak and other TOU tariffs are available. However, the differences in peak and off-peak prices is minimal and not reflecting underlying variations in wholesale and network costs.
Latvia			X	Off-peak tariffs are available, but few incentives exist in distribution or TSO tariffs
Lithuania			X	Tariffs are differentiated between day and night.

[68] Kollmann, A. et al., 2013, Lastverschiebung in Haushalt, Industrie, Gewerbe und kommunaler Infrastruktur – Potenzialanalyse für Smart Meter – Loadshifting
[69] AF Mercados, 2015, Study on tariff design for distribution systems.
[70]CEER, 2013, Regulatory and Market Aspects of Demand-side Flexibility, http://www.ceer.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/Demand-side_flexibility/RR)
[71] Thema Consulting Group, 2014, Demand Response in the Nordic electricity market. Input to strategy on demand flexibility
[72] Pöyry, 2015, Demand Side Response as a source for flexibility. Available under: http://elering.ee/public/Infokeskus/Demand_Side_Response_as_source_for_flexibility.pdf
[73] Thema Consulting Group, 2014, Demand Response in the Nordic electricity market. Input to strategy on demand flexibility
[74] Mavir, 2016, Available under: : https://www.mavir.hu/web/mavir-en/code-of-commerce

Member	Spot prices (Real time)	CPP	TOU	Comments
Luxembourg			X	TOU tariffs are available.
Malta				For non-residential larger consumers there is a day- and night tariff.
Netherlands	X	X	X	TOU, CPP, Real Time Pricing and Peak Time Rebate (PTR) are already an option. SEDC reports effective price based reponse by green-house owners.
Poland			X	ToU Tariff available
Portugal			X	Consumers have access to dynamic prices (since 1997), but most consumers chose flat tariffs.
Romania			X	Seasonal and on-peak tariffs are available.
Slovakia			X	Smaller consumers do not participate in DR (legally allowed, but probably due to the lack of technology). Larger consumers participate mostly through incentive-based contracts.
Slovenia		X	X	TOU and CCP are applied in Slovenia, and they are established under Article 98 of the "Act on the methodology determining the regulatory framework and the methodology for charging the network charge for the electricity system operators". The introduction of intelligent metering is outlined as a key factor for the participation of consumers in network efficiency in the Slovenian NEEAP.
Spain			X	TOU are offered. Wholesale price pass through tariffs apply to some customers - might differ on a daily basis as the share of the electricity part of the tariff reflects the daily wholesale price formation.
Sweden			X	TOU are offered to all customers by some grid companies. Mandatory for customers with main fuses above 80 A[75]. Focused on enabling price-based DR through smart meter rollout and dynamic tariffs.
UK			X	ToU tariffs exist for small medium consumers (e.g. Economy 7 and Economy 10 tariffs) and I&C sector (TNUOs charges (Triad avoidance)).

Sources: Various, including the on-going work of JRC (2016)

In general, the above table does not suggest widespread shifting behaviour from ToU tariffs. As data on price based DR is not readily available, experiences in selected MS geographically spread across Europe, and with a mix of existing practices, are considered to see if it is possible to develop a representative estimate of price based DR at an EU-wide level. The countries considered are:

- UK
- Germany,
- Spain,
- Finland, and
- France.

United Kingdom

ToU tariffs have been in place in the UK since the 1970s for smaller consumers. In 2015 around 13% were subscribed to TOU tariffs,[76] most of them on the Economy 7 or the Economy 10 tariff. Key features of these tariffs are as follows:

---

[75] Thema Consulting Group, 2014, Demand Response in the Nordic electricity market. Input to strategy on demand flexibility.
[76] Fell, M. and others, 2015, Is it time? Consumers and time of use tariffs.

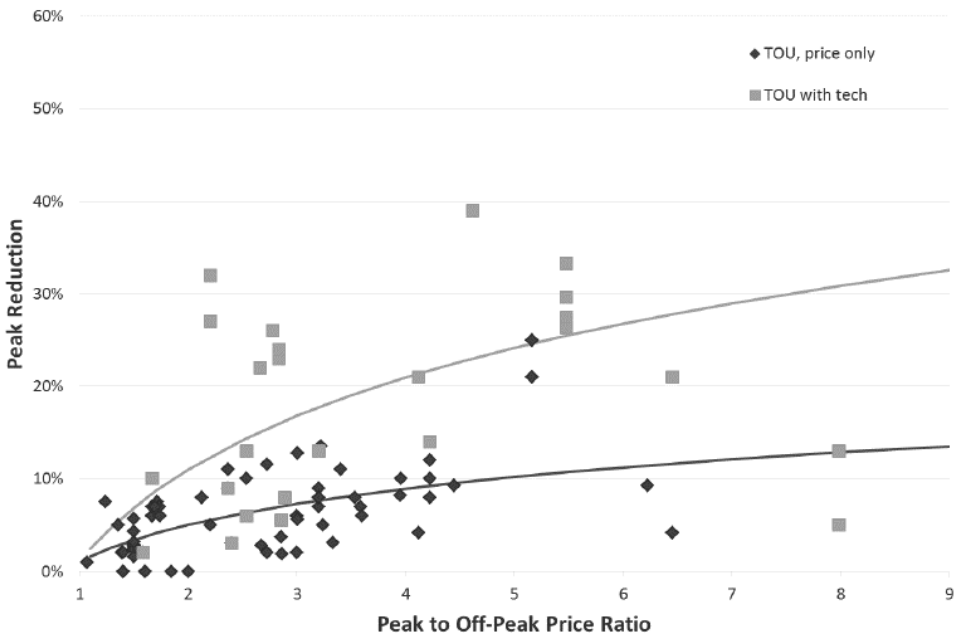
- "Economy 7" – offering lower electricity tariffs for 7 hours at night (mainly targeting night storage heaters) – the difference between peak and off peak tariffs is generally in the range of 1.5-1.8.

- "Economy 10" – offering off-peak tariffs in various blocks of 2, 3 and 5 hours. This tariff is not offered by all suppliers.

Both tariffs currently tend to be limited to consumers with electric resistance heating. Moreover, they are gradually being phased out by suppliers.

There is limited research on the impact that price differentials in two-part tariffs can have on load shifting. One of the more comprehensive studies is that of Faruqui, which supports a non-linear relationship between the ratio of peak and off-peak price. His research distinguishes between ToU pricing and dynamic pricing. For ToU tariffs his estimated relationship shows roughly 5% reduction in peak demand for a 2:1 ratio of peak to off-peak pricing.

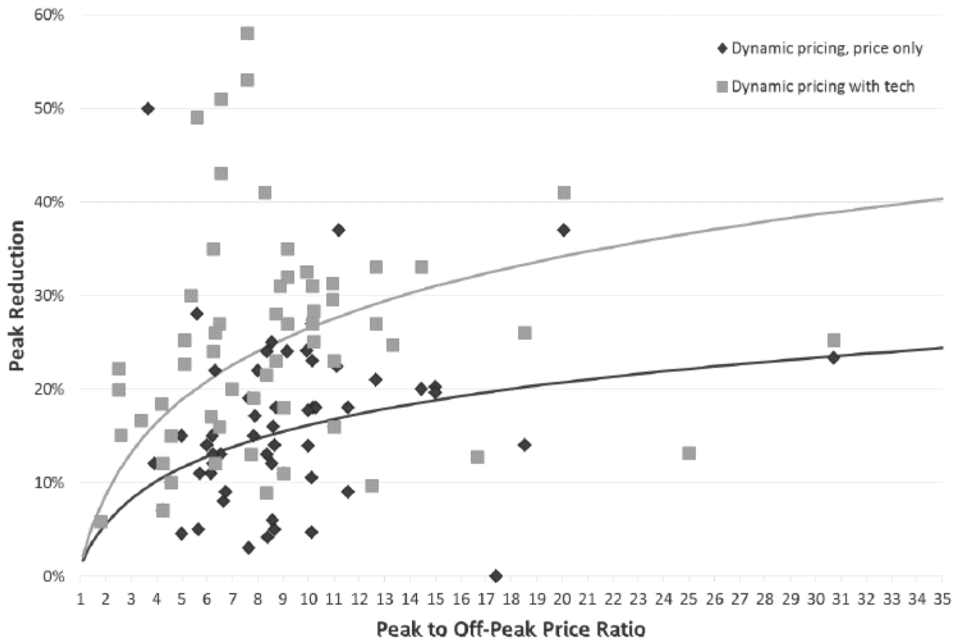
Figure 3: Relationship between price differential peak/off-peak and peak reduction (TOU)



Source: Own elaboration, according to Faruqui, Ahmad. "Arcturus." The Brattle Group.

In the case of dynamic pricing, observations are largely concentrated in larger peak to off-peak price ratios. For a price ratio of the order 6-8, a peak reduction of 12-15% is estimated.

Figure 4: Relationship between price differential peak/off-peak and peak reduction (Dynamic)



Source: Own elaboration, according to Faruqui, Ahmad. “Arcturus.” The Brattle Group.

Faruqui´s numbers need to be treated with caution given that much of the evidence – particularly for dynamic pricing - is from trial data with customers notably incentivised to participate.

Applying Faruqui´s figures to the UK, where a price differential for Economy 7 and 10 of roughly 1.7 is observed, suggests a peak reduction of around 4%. If this is combined with the fact that only 13% of smaller customers have these tariffs, the reduction in peak demand resulting from these tariffs would be little more than 0.5% of the residential component of the peak.

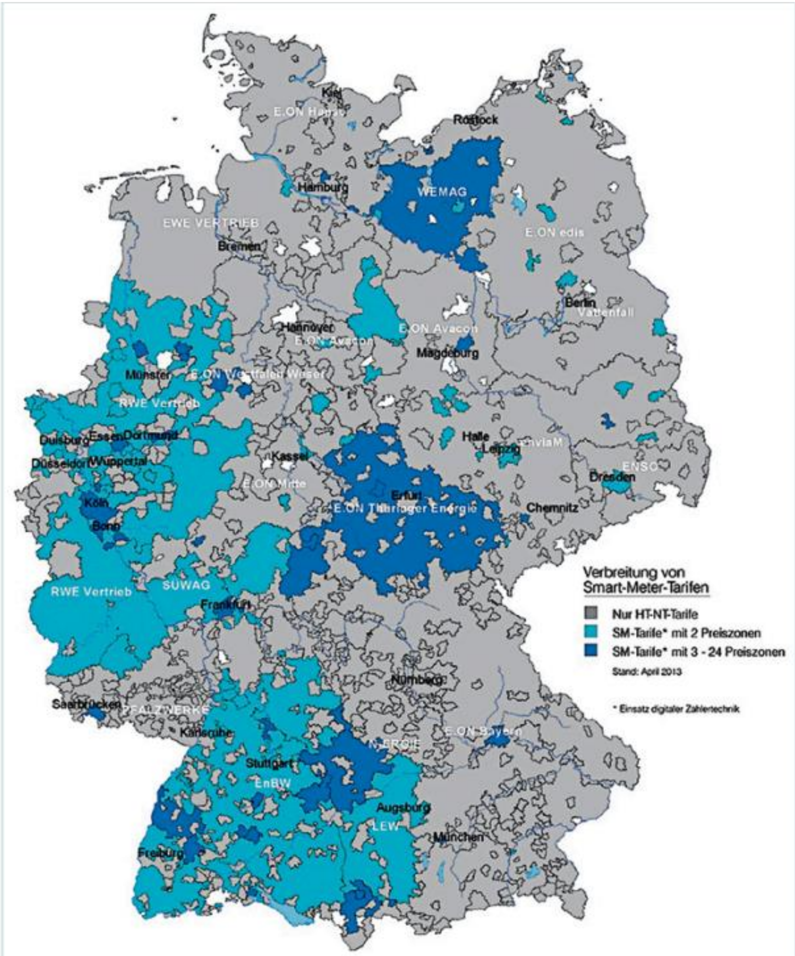
In the UK, larger consumers are equipped with advance meters or smart meters that allow half-hourly meter readings, and which permit tariffs ranging from half-hourly real-time wholesale pricing, to static TOU tariffs. There is currently little evidence of large time-based differentials in tariffs, which suggests that peak load shifting may not be significantly higher than for residential customers. While any estimate of the total price-based impact is subject to value judgements, on the whole a total shifting of no more than 1% of peak load appears plausible.

Germany

ToU tariffs have been available for smaller consumers since the 1970s. The predominant availability of particular tariffs is set out in the table below. However, it is not known how many suppliers currently offer a ToU or dynamic tariffs. In

2013, 76 % of the electricity suppliers offered some kind of time-varying tariff[77], yet most of them only offered a two part tariff with different tariffs for day and night hours.

Figure 5: Map of TOU in Germany



Source: Ene't GmbH, 2011[78]

Grey: Night-and Day time supply tariffs, Turquoise: 2-part tariff, Dark blue: 2-23 part tariff

The most common tariff provided by regional suppliers to smaller customers is the off-peak supply tariff (night-time electricity supply tariff), which is aimed at storage heaters. However, over time the availability of this tariff is declining, while at the same time prices are converging between peak and off-peak periods. The other types of tariffs (Turquoise: 2-part tariff, Dark blue: 2-23 part tariff) are less common. Moreover, generally the difference is just a few cents per kWh and thus it does not have a great effect on load shifting.

---

[77] Bundesnetzagentur & Bundeskartellamt, 2014, Monitoringbericht 2014

[78] Ene't GmbH, 2011, Anzahl der Versorger mit Smart-Meter-Tarifen seit Januar verdoppelt. Available under: https://www.enet.eu/newsletter/anzahl-der-versorger-mit-smart-meter-tarifen-seit-januar-verdoppelt

At the same time, fewer people are using storage heating, as Government has taken explicit decisions not to subsidise storage heating due to environmental reasons. These factors indicate that the estimated load shift for smaller customers will be low and probably comparable to the level of the UK.

The JRC (2016) reports that larger customers make greater use of on- and off-peak, and even real-time tariffs. However, there is limited evidence of customers shifting to off peak periods to reduce their energy costs. Moreover, Government is opposing the continued use of simple TOU tariffs on the grounds that they do not reflect environmental costs, nor changed conditions in the wholesale market due to the wider spread of renewable energy.

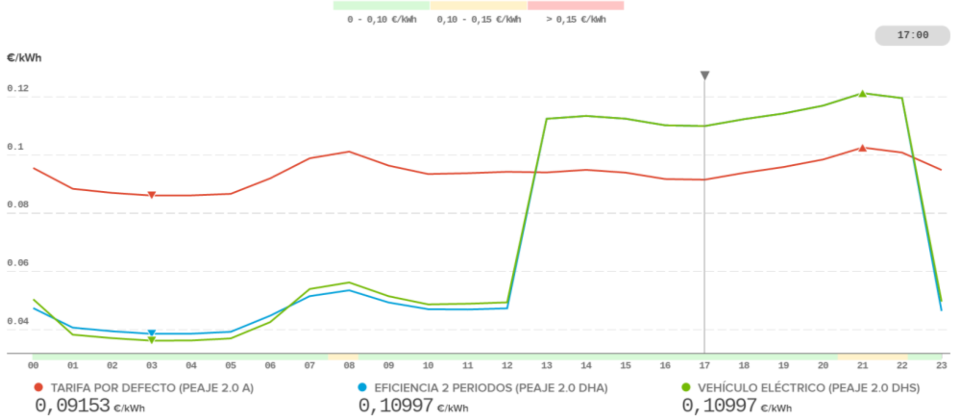
Based on the UK benchmark above, the amount of peak load shifting is also likely to be less than 1%.

Spain

In Spain the main regulated tariff for households (< 10kW) is the PVPC tariff. Around half of all households were supplied under this tariff in 2015, while the other 50% were supplied by free market electricity retailers.

The share of the electricity components of the final PVPC tariff is calculated on a daily basis based on the wholesale market price formation. The full wholesale price is passed through to the consumer.

Figure 6: Time-of Use tariff for small consumers in Spain



Source: Red Electrica de España, 17 May 2016

Electricity consumers under the regulated PVCP tariff can choose between the standard tariff or the two-part tariff, independently if they have a smart meter installed in the house. For households without smart meters, an hourly price is determined based on a standard consumption profile used by the TSO. In the example shown from 17 May 2016, the lowest tariff during the day was 0,039 €/kWh and the highest tariff 0,121 €/kWh at 21:00h, resulting in a ratio of around 3,1, much greater than that of the Economy-7 tariff in the UK.

The above tariffs are new and relatively innovative, and expose customers with a smart meter and who have not signed a supply contract to pool price volatility. However, there is no evidence that customer behaviour is being influenced to date by these tariffs – partly as they are new and partly as customers on a default tariff are typically less responsive to price changes. Moreover, participation in ToU tariffs in Spain is traditionally low for various reasons:

- The electricity part of the tariff is relatively low – accounting for around 40% of the bill, with the remaining largely invariant to usage.

- Generally, customers are able to save more money by contracting a tariff that limits the total capacity than altering consumption patterns.

The Ministry of Energy reports that as of 2014 there was 1300MW of price based DR from customers on ToU tariffs and with contracted demand <15kW and 1000MW for large industrial customers[79]. However, these figures, which imply a 5.5% shift in peak demand, appear unrealistic compared with customer-level data on ToU tariffs. On the whole the evidence suggests that the extent of price-based demand response is no higher than in UK or Germany, and potentially lower due to the lower spread of space heating.

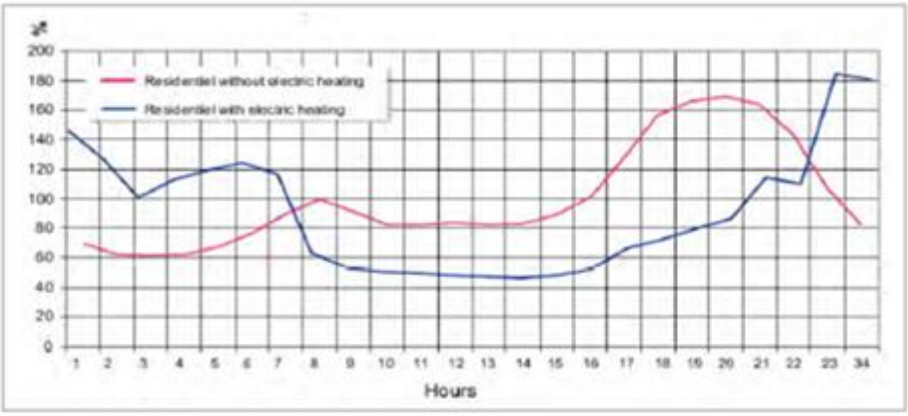
Finland

ToU tariffs are commonly used in Finland. Since the 70s, large price variations between day and night have given Finnish households an incentive to install the necessary equipment to move a large share of their electrical consumption from day to night. In particular, there is a very large DR potential in the form of space heating installations and large water tanks. Moreover, smart meter installation, the time switch, water based heat distribution and tanks for accumulating and storing heat makes it possible for Finnish households to take advantage of price differences to lower their total electricity costs (Toivonen, 2013).

The following figure illustrates how Finnish households with electric heating exercise their flexibility by moving their electricity demand from day to night. Residential buildings without electric heating have a normal load profile, with their largest demand occurring during the daytime, while that of buildings with electric heating have the largest demand during the nighttime.

[79] Planificación Estratégica: Plan de Desarrollo de la Red de Transporte de Energía Eléctrica 2015-2020, Ministerio de Inustria, Energía y Turismo, Gobierno de España

Figure 7: Load profile of residential customers in Finland



Source: VTT (2007)

The total impact of the load shifting is uncertain. Research by THEMA (for Nordic Energy Research in 2014) suggests that approximately 90,000 villas have heat storage that each comprise between 9-19kW (average around 12kW) from peak hours to the nightime. In total this suggests around 1000MW may be taken away from peak load in Finland – potentially as high as 6% of winter peak demand. In fact, other studies suggest an even higher load shifting: the IEA (2011) reports 2000MW load shifting by the programme affecting up to 15% of peak demand. However, in the Finnish case ToU pricing needs to be seen in the context of a package with heat storage and load control system.

The Finnish experience is not directly applicable to other Nordic countries in the EU. For example, there are no similar examples of load shifting in Sweden as Sweden relies mainly on district heating. Furthermore, while there are a lot of homes with electric heating – though not at the same scale as in Finland - they do not have heat storage. In the case of tariffs there are conflicting signals regarding price sensitivity – on one hand the volume of customers taking variable energy prices is increasing, while the fixed component of grid tariffs has been gradually increasing since deregulation.

France

France is an important case study as it provides examples of CPP. Électricité de France (EDF) offers different tariff options for small/ medium consumers: a standard tariff, a two part tariff with 8 off-peak hours per day, and the EDF Tempo tariff.

The Tempo tariff is available for private household consumers as well as small business customers with a minimum capacity of 9kVA since 1995. The Tempo tariff unites two pricing structures in a single tariff – TOU and event pricing which adds up to a total of six price categories. The TOU part of the tariff divides each day in peak (6h00 to 22h00) and off-peak hours (22h00 to 6h00). The CPP part of the tariff sets the actual price/kWh for each day. The days are divided into red, white and blue days as follows:

- Red days (0-22 days per year) – are the most expensive days. For the period 2015/16, they could not take place from the 1st of November to the 31st of March. In addition, Saturday and Sundays cannot be red days.

- White days (0-43 days per year) – are less expensive than the red days. In principle they can be distributed throughout the year, but they rarely occur between May and October. They cannot be on a Sunday.

- Blue days (105-301 days per year)– all remaining days are blue days (cheapest days). Every Sunday of the year is obligatory a blue day.

Each day around 5:30 pm the colour of the following day is published on the webpage of EDF. The signal is also transmitted to the customer and displayed both on their meter and on a small box which can be plugged into any power socket.

The table below displays the current Tempo tariffs[80] and the ratio compared to the blue day tariff for the red and white days.

Table 4 Tempo Tariffs after the 1st of January 2016 (c€/kWh)

Colour of the day	Peak tariff	Off-peak tariff	Peak-tariff ratio compared to the blue rate tariff
Red	62,07	24,02	5,4
White	15,85	13,36	1,4
Blue	11,47	9,67	n.a.

Source: EDF, 2016[81]

The tempo tariff is well designed for the French electricity market as electrical heating drives peak consumption in France, and where peaks arise they generally affect particular days than a few hours.

Studies have been previously undertaken to measure the effect of the tempo tariff on the national consumption and peak load reduction in France[82]. The following results were obtained:

[80] They do not differ depending on the contracted capacity.
[81] EDF, 2016, Option Tempo. Available under: https://particulier.edf.fr/fr/accueil/facture-et-contrat/contrat/consulter-les-jours-ejp-et-tempo/option-tempo.html
[82] Studies might differ, as parameters such as consumer partipation, the tariff ratios etc. changed over time.

- compared to the lowest price level, customers have been measured reducing consumption by 15% on the second highest price level and by even 45% on the highest price level[83];

- 4% of national peak shifting[84].

It is also reported that a further 6 GW was traditionally shifted daily by the day-night tariff (with price differential currently around 1.46) that is offered to the 27% (10 million households) of homes that have electric water heaters. Many consumers have automated water boilers that are programed to response to tariff changes.[85] However, many organisations, including the IEA believe that with the opening of electricity supply to competition the amount of traditional demand side response has fallen and is closer to 2 GW. A much lower value (than 6GW) is also consistent with the response of some participants in the interview phase of the project, who report that CPP and ToU have not been particularly successful,[86] with much of the benefit arising from controlling water heating and boilers.

Summary

In general, there is limited evidence of price based DR in the EU, and only in specific situations, namely:

- Where there is a big price difference between peak and off-peak prices, and
- There are appliances that permit customers to easily shift usage from peak periods to off peak periods.

These conditions are most prevalent in Finland, where there is a sufficient difference between on-peak and off-peak electricity prices, and many customers have appliances like storage heaters and hot water tanks, that make it beneficial to shift demand to off-period periods. Moreover, the system in Finland works with smart meters, suggesting it can be more easily adapted to changed market conditions – and hence is sustainable. The data from France also supports a higher load shifting through traditional tariff means, though this traditional form of price response has been declining dramatically in magnitude in recent years.

Where these conditions do not apply, customers appears less willing to change behaviour under flexible tariffs, with a likely finding that customers are expected to choose a ToU tariff where its existing load profile results in lower bills under ToU tariffs.

---

[83] Intelligent Energy Europe, 2013, European Smart Metering Landscape Report 2012 – updated 2013.
[84] Pöyry, 2012,Time of Use tariff Mandate. A Report to the Commission for Energy Regulation.
[85] Pöyry, 2012,Time of Use tariff Mandate. A Report to the Commission for Energy Regulation.
[86] This was the response of a French aggregator during the interview process.

In some cases, for example, the Czech Republic (and to a lesser extent, Hungary), significant load of around 2500MW (or between 10-15% of peak winter load) has been moved to off-peak periods using ripple control systems, for which ToU tariffs are applied. However, in this case, the load shift cannot be considered to be price-related or even incentive based related as the shift is largely administrative in nature.

As a high level estimate for EU, studies and data support current load shifting due to price based DR ranging from negligible (most MS), to around 1% (most Northern European Countries), 2.5% (France) and 6-7% (Finland). If a value of 1% is applied for Northern European countries and those with some reported DR (e.g., Spain), 2.5% for France and 6% for Finland, the overall load that is shifted due to ToU tariffs to date would be of the order of 5.7GW or 1.2% of peak load. This estimate should be seen in the context that:

- The vast majority of this shifting is not related to economic costs in the wholesale or network segment of the market (Finland appears an exception), and
- Traditional static ToU tariffs are being phased out, and hence this limited shifting may not be applicable once smart meters are installed.

As a cross check these values are compared with the Gils estimates of DR potential as per section 5.2. The amount of price-based DR in Finland considered above is around the Gils potential for the relevant consumption categories, which is consistent with the Finnish system being well developed and run. The estimates quoted for France are above the Gils benchmark, which may suggest that under less rigid and more market-driven approaches a lower (but more efficient) price response is likely. This conclusion is consistent with concerns in France about likely further reductions in price based DR.

Note that as a proportion of the Gils potential the estimate of price-based DR in 2016 is around 9%.

5.3.2 Estimates of price based DR in future years

In developing estimates of price-based DR in future years – under both the BAU and Option 1 scenarios - the following variables have been considered:

- Demand susceptible to price-based DR.
- Time profile of smart meter installation.
- Customer take up of new tariffs.
- Demand impact of ToU, RTP and CPP.

5.3.2.1 Demand susceptible to price based demand response

In considering changes from policy measures, focus is placed on residential and small commercial customers as it is assumed that most industrial and large commercial customers have a smart meter in place, and are already eligible for time-based prices. Moreover, larger customers are most likely to participate in demand response through incentive-based measures. In this sense, the main incremental impact that policy measures can have relate to residential and small commercial customers. At the level of peak demand there is little data on contribution by sector. However, at the EU-28 level, approximately 30% of energy consumption is due to residential customers, and an additional 30% due to commercial customers and public services.[87] This suggest that if half of commercial consumption is susceptible for price based demand response, and consumption share approximates share in peak demand, then roughly 45% of total demand is accounted for by residential and small commercial customer categories.

An estimate of the amount of demand that is susceptible to demand response is taken from the database developed by Gils and described in the previous section. Consistent with the above assumption, the total load reduction potential for price based demand response by MS is taken as the sum of the potential for all categories of residential load plus half that of the commercial consumption categories. As stated, this estimate is simplistic, but as a reasonably similar share of commercial demand is likely to participate through incentive-based means – and captured by the subsequent analysis on incentive based demand response - the overall picture should not be misrepresented unduly.

The following tables summarises the load reduction potential through price based DR for 2016, 2020 and 2030 estimated using the Gils database. The estimate for 2016 is made using linear interpolation from the data for 2010 and 2020. This data differs from that set out in the previous section as it includes only the following components:

- All residential and half of commercial load reduction potential.
- Half of the proposed electric vehicle load reduction potential.
- One-quarter of the proposed heat pump load reduction potential

Table 5 Estimate of residential and small commercial load reduction potential using Gils (2015) data, 2016, 2020, 2030 (MW)

Member State	2016	2020	2030
Austria	1284	1421	2050
Belgium	1775	2026	3096
Bulgaria	644	664	830
Croatia	394	412	527
Cyprus	134	143	186
Czech Republic	1123	1194	1536
Denmark	972	1064	1570
Estonia	173	181	226
Finland	1610	1738	2348
France	11551	12924	18713
Germany	12869	14345	21397
Greece	1565	1661	2031
Hungary	1008	1037	1241
Ireland	681	792	1264
Italy	9303	10772	15981

[87] Based on data in Eurostat, Energy Balance Sheets 2013 data, 2015 edition.

Member State	2016	2020	2030
Latvia	220	233	277
Lithuania	302	309	361
Luxembourg	80	84	85
Malta	61	64	67
Netherlands	2557	2848	4088
Poland	3534	3703	4562
Portugal	1165	1301	2107
Romania	1449	1495	1749
Slovakia	692	737	887
Slovenia	261	276	348
Spain	6623	7507	11654
Sweden	2984	3222	4110
UK	9788	11013	16273
TOTAL	**74802**	**83169**	**119563**

Source: Own calculations, adapted from Gils (2015).

The database shows demand response potential for the selected customer groups growing over time as the share of electric vehicles and heat pumps increases. The Gils figures on electric vehicles and heat pumps have been amended for the following reasons:

- Research by Ecofys[88] that models the demand profile for 100 households, 94% of which have an EV, with and without demand response from EVs. The modelling shows that the peak is reduced from 420kW to 240kW using smart charging (no vehicle-to-grid). Per EV this is around 2kW of a charging capacity of 3.7 kW – that is roughly 50%.
- For Heat Pumps, the reduction potential is limited because the heat demand profile of well insulated houses is already quite flat. There can be interaction with other demand peaks (appliances and electric cars) which makes the overall profile less peaky. On the whole a value of around 25% is assumed.

5.3.2.2 Time based profile of smart meters

The time based profile of smart meter installation and use is considered at two key levels:

- MS roll out profiles up to 2020 and beyond; and

- The proportion of installed smart meters that permit the use of dynamic tariffs (ToU, RTP, CPP).

[88] Ecofys, Waarde van Congestiemanagement, http://www.ecofys.com/nl/publications/waarde-van-congestiemanagement/

An estimate of the smart metering roll-out is based on the roll-out profiles reported in the European Commission's Benchmarking report (2014).[89] Different profiles are estimated for the BAU and Option 1 scenarios.

In the case of BAU the reported roll out profiles are as the Benchmarking report for the period to 2020, with the following additional assumptions made:

- For countries with no reported CBA[90] no roll out is assumed up to 2030, and hence no dynamic tariffs for the entire period.

- For countries with a CBA with negative or inconclusive results[91] the proposed roll-out of the MS is applied. In some cases this amounts to no roll out, in others cases a roll out of much less than 80% metering points is proposed.[92]

- For some countries, where installation progress in 2016 is well down on the values assumed in the Benchmarking Report an adjustment is made to better reflect the actual situation.[93] However, no changes to the 2020 figures are included.

In addition, in the BAU scenario, a subset of the MS reporting a large scale roll out by 2020 are assumed to have metering systems fully designed to accommodate dynamic tariffs, and with such tariffs widely available to customers. This categorisation is largely based on existing policy statements. Six MS – Denmark, Finland, Ireland, Spain, Sweden and the United Kingdom - are assumed to offer ToU or dynamic tariffs for domestic and small residential customers in 2020 without the need for any change in policy.

In practice, the requirement for two-way communication is not always clear cut. For example, all Spanish suppliers will offer three-tier ToU tariffs in 2020, but some will do so through software modifications rather than two-way communications. Moreover, it is not always necessary to have two-way communication to benefit from RTP or CPP – for example, where the actual prices are available on the internet. Due to the observation that two-way communications is not always necessary, for other countries engaged in a large-scale roll-out it is reasonable to assume that by 2020 a high proportion of customers will be eligible for ToU, RTP and CPP. In this case, 75% of customers are assumed eligible in 2020 and all by 2030.

---

[89] European Commission, Report from the Commission: Benchmarking smart metering deployment in the EU-27 with a focus on electricity (COM(2014) 356 and SWD(2014) 188), June 2014.
[90] Bulgaria, Croatia, Cyprus, Hungary, Slovenia.
[91] Belgian jurisdictions, Czech Republic, Latvia, Lithuania, Germany, Portugal, Slovakia
[92] This is the case in Germany, Latvia and Slovenia.
[93] This is the case in Austria (1 year delay); France, Netherlands and Romania (all half the assumed value for 2016); and Germany, Greece and Slovakia (no installation as of 2016).

The resulting estimates of metering points with smart meters, and the availability of dynamic tariffs for the BAU scenario are set out below.

Table 6: BAU - Estimate of metering points with smart meters, and capability for dynamic tariffs 2016, 2020, 2030

Member State	**2016**	**2020**	**2030**	**Widespread availability of dynamic tariffs 2020**
Austria	10%	95%	95%	75%-
Belgium	0%	0%	0%	-
Bulgaria	0%	0%	0%	-
Croatia	0%	0%	0%	-
Cyprus	0%	0%	0%	-
Czech Republic	0%	0%	0%	-
Denmark	76%	100%	100%	100%
Estonia	79%	100%	100%	75%
Finland	100%	100%	100%	100%
France	20%	95%	95%	75%
Germany	0%	23%	31%	75%
Greece	0%	80%	80%	75%
Hungary	0%	0%	0%	-
Ireland	20%	100%	100%	100%
Italy	99%	99%	99%	75%
Latvia	0%	80%	95%	75%
Lithuania	0%	0%	0%	-
Luxembourg	48%	95%	95%	75%
Malta	100%	100%	100%	75%
Netherlands	25%	100%	100%	75%
Poland	32%	80%	100%	75%
Portugal	0%	0%	0%	-
Romania	18%	80%	100%	75%
Slovakia	0%	23%	23%	75%
Slovenia	0%	0%	0%	-
Spain	70%	100%	100%	100%
Sweden	100%	100%	100%	100%
UK	39%	97%	100%	100%
AVERAGE	**35%**	**71%**	**74%**	

Source: Own analysis based on figures in Commission's Benchmarking Report and new information from Latvia

In the case of smart meters being available on demand (Option 1), the following assumptions are made on the roll out of smart metering systems:

- In countries with a reported large-scale roll out of smart metering systems, the roll out occurs as planned. In all cases, customers will have access to dynamic tariffs by 2020. This reflects greater customer and supplier awareness of the benefits of smart meters.

- In countries with either a limited roll out or no planned roll out, smart meters will be made available to customers on demand.

The extent to which customers will choose the installation of a smart meter will depend on a range of factors, including the proportion of overall benefits that it could capture. Where a customer is faced with the full cost of smart metering installation, extremely low take up is envisaged in the relevant MS based on current technology use. The following table undertakes simple calculations of the ratio of customer benefits to total costs based on analysis undertaken for the

Commission on the cost-benefit analysis of smart metering of countries for which a large scale roll-out was not proposed at the time of publication.

Table 7: Estimate of costs of smart meter roll out and relationship with customer related benefits, per metering point (€/metering point)

	BE-BRU	BE-FLA	BE-WAL	CZ	DE	HU	LT	PT	SK
Key costs									
Meter	250,24	330,03	303,92	243,74	189,20	104,62	103,64	56,32	91,72
IT	70,79	60,08	60,91	96,23	84,17	9,58	12,73	5,18	27,34
Communications	108,56	11,36	42,43	57,43	149,27	45,22	34,85	29,59	75,40
Other	29,75	37,88	17,65	16,13	42,47	42,60	15,06	7,02	
TOTAL	**459,34**	**439,35**	**424,90**	**413,53**	**465,11**	**202,02**	**166,28**	**98,11**	**194,46**
Key customer related benefit									
Consumption	**130,00**	**54,40**	**52,10**	**1,20**	**199,70**	**6,30**	**35,90**	**30,90**	**148,90**
Ratio cost/benefit	**3,53**	**8,08**	**8,16**	**344,61**	**2,33**	**32,07**	**4,63**	**3,18**	**1,31**

Source: Calculations from Tables 8 and 11 of AF Mercados, NTUA (2015), Study on cost benefit analysis of Smart Metering Systems in EU Member States, Final Report. Note: BRU – Brussels, FLA – Flanders, WAL - Wallonia

The above calculations from the MS own data show that customer related benefits from smart metering systems (on a per-metering point basis) are generally significantly lower than corresponding per-metering point costs. In the two cases in the above table where the ratio of costs to benefits is closer to 1 it is notable that the MS has based its analysis and/or decisions on mandatory roll out for customers above a certain consumption threshold:

- In Germany a mandatory roll out for all customers above 6000kWh is proposed.

- In Slovakia, the CBA only considers customers with consumption above 4000kWh (covering 23% of metering points and 53% of LV consumption).

The German and Slovakian analysis suggests that customers with consumption above 5-6,000kWh may choose, or be close to choosing, to take up a smart meter even if it were to bear the full costs. The data from other MS cost benefit analysis is less clear-cut as the analysis considers all customers – and hence a higher ratio of cost to benefit is not surprising. Other analysis is also less clear cut – for example, the case of Sweden where smaller customers can request charging on the basis of hourly prices at zero cost. The change in tariff requires a change in the functionality of the metering point to allow regular data transfer. However, as of 2013, only 6,300 households out of a total of 4.5 million had hourly metering. The Swedish Energy Agency advise stated that the number has not increased significantly in the subsequent period.

For the purpose of analysis, it is assumed that for all countries without a full roll out of smart meters, take up of a smart meter for reasonable customer contributions will be low in the short to medium term (up to 2020). However, it may well increase significantly in the subsequent period to 2030 as the costs of meters, communications and information technology are expected to fall, and the spread of appliances conducive to price-based demand response are anticipated to rise. Therefore, the following estimates are assumed:

- Take up of smart meters of around 10% of residential and small commercial customers by 2020.
- Take up of smart meters of 40% by 2030.

The resulting estimates of smart meter roll out and access to dynamic tariffs under Option 1 are set out below. It is assumed that suppliers will offer most forms of dynamic tariffs under this policy option, and that appropriate metering will be installed that permits the required functionality.

Table 8: Option 1 - Estimate of metering points with smart meters, and capability for dynamic tariffs 2016, 2020, 2030

Member State	**2016**	**2020**	**2030**	**Widespread availability of dynamic tariffs 2020**
Austria	10%	95%	95%	Yes
Belgium	0%	10%	40%	Yes
Bulgaria	0%	10%	40%	Yes
Croatia	0%	10%	40%	Yes
Cyprus	0%	10%	40%	Yes
Czech Republic	0%	10%	40%	Yes
Denmark	76%	100%	100%	Yes
Estonia	79%	100%	100%	Yes
Finland	100%	100%	100%	Yes
France	20%	95%	95%	Yes
Germany	0%	23%	40%	Yes
Greece	0%	80%	80%	Yes
Hungary	0%	10%	40%	Yes
Ireland	20%	100%	100%	Yes
Italy	99%	99%	99%	Yes
Latvia	0%	80%	95%	Yes
Lithuania	0%	10%	40%	Yes
Luxembourg	48%	95%	95%	Yes
Malta	100%	100%	100%	Yes
Netherlands	25%	100%	100%	Yes
Poland	32%	80%	100%	Yes
Portugal	0%	10%	40%	Yes
Romania	18%	80%	100%	Yes
Slovakia	0%	23%	40%	Yes
Slovenia	0%	10%	40%	Yes
Spain	70%	100%	100%	Yes
Sweden	100%	100%	100%	Yes
UK	39%	97%	100%	Yes
AVERAGE	35%	72%	81%	

Source: Own analysis based on figures in Commission's Benchmarking Report

5.3.2.3 Customer take up of dynamic tariffs

The take up of dynamic tariffs for customers with smart meters is modelled using the findings of a study by Redpoint Energy (2012) for the UK Department of

Energy and Climate Change (DECC).[94] This study modelled the impact of demand side response in the UK up to 2030, and included estimates of the take up of tariffs with strong price based incentives, including static ToU (STOU) and critical peak pricing (CPP) following the large scale roll-out of smart meters. The report defines STOU as a tariff that differentiates unit prices for different blocks of time across the day and CPP as a pre-specified high tariff applied for usage during periods designed by the supplier as critical peak periods. The study was chosen due to several reasons:

- Its findings are broadly in accordance with the results of a majority of international studies;
- It is one of the most detailed studies undertaken in Europe that differentiates between the uptake of DR from price-based and incentive-based mechanisms and includes forecasts to 2030;
- It considers and distinguishes between important parameters, such as the effect of different types of tariffs on DR, the implications of electric vehicles and heat pumps; and
- It includes sensitivity analysis.

The core estimates in the study are presented below:

Table 9: Take up of STOU and CPP – Redpoint Energy estimates for the UK

Type of tariff	**Demand/ electrification Scenario**	**2015**	**2020**	**2025**	**2030**
Static ToU	Low	8%	18%	16%	18%
	Central	**8%**	**18%**	**20%**	**26%**
	High	8%	18%	20%	33%
CPP	Low	0%	2%	6%	9%
	Central	**0%**	**3%**	**10%**	**16%**
	High	0%	3%	12%	19%

Source: Redpoint Energy (2012)

The results suggest that the expected take up of ToU tariffs will gradually increase up to 2030, while those of CPP will increase by more than 5 times. The figures for 2020 – when the full roll out is expected to be in place in the UK - are reasonably consistent with Scandinavian data on the take up of dynamic tariffs by customers.

However, the above estimates were made for the UK, a country with a full roll out of smart meters planned. In the case of an optional take up of smart meters (as per Option 1) a much higher take up of dynamic prices is anticipated as customers opting for a smart meter are most likely to do so exactly because they can make savings from doing so. For that reason, the take up of one of STOU, RTP or CPP in these cases may well be universal, or at least double the estimates presented here (44% taking one form of dynamic pricing).

[94] Redpoint Energy (2012), Electricity System Analysis – future system benefits from selected DSR scenarios, Final report pack, August 2012.

These numbers have been applied in the following manner for MS's proposing a full scale roll out of smart meters:

- First, Redpoint Energy's central figures are taken as the most representative.

- Second, an estimate of the take up of dynamic tariffs for customers who have a smart meter in place in 2016 is made by a combination of linear interpolation and scaling up the 2015 values by the proportion of customers who will have a smart meter in place. On that basis, the potential take up by customers with a smart meter of static ToU tariffs in 2016 is estimated at 10%.

- Third, it is assumed that these figures (and those for the roll out) already take into account customers who for technical and other reasons cannot access time of use charges. For example, the Irish CBA report[95] includes an adjustment value of 11% for inaccessible customers who may for example, have a smart meter but for which 2-way communications is not feasible. This could be the case if there are challenges regarding the accessibility of certain private residences, which are vacant on a long-term basis, for example holiday houses.

- Fourth, these values are applied uniformly across this sub-category of MS. That is, it is assumed that that take up of dynamic tariff per equipped smart meter is equal across MS for a particular year. The same assumption applies in the BAU and Option 1 scenarios. Thus, the assumptions do not consider possible effects of extra incentives that might be given by different EU MS in order to stimulate a faster price-based response.

The resulting take-up estimates are as follows:

- Static TOU: 2016 – 10%, 2020 – 18%, 2030 – 26%

- CPP: 2016 – 0%, 2020 – 3%, 2030 – 16%.

In the case of MS not currently planning a large scale roll out of smart metering systems, and for which optional take up applies under Option 1, the same methodology applies but with the take up rate for static TOU and CPP doubled in 2020 and 2030 for customers with a smart meter (52% and 32% respectively in 2030).

The core estimated figures are in line with international trial studies and practical evidence, including:

---

[95] NSMP (Electricity & Gas (Cost Benefit Analysis), PWC Report

- The consumer survey of "Smart Energy GB survey",[96] which states that around 30% of the people were either strongly or moderately in favour of switching to a STOU tariff;

- The take-up rate of the CPP tempo tariff in France that was slightly less than 20% of the total consumers.

5.3.2.4 Price impact of dynamic pricing

An estimate of the load reduction impact of STOU and CPP mechanisms is made based on the findings of previous studies.

Care needs to be taken when extrapolating from previous results as a number of critical variables tend to affect study findings, as noted by Faruqui (2013)[97], including:

- The ratio of peak to off peak price - the amount of demand response increases as the peak to off-peak price ratio increases but at a diminishing rate;

- The length of peak period;

- Number of pricing periods in a day;

- Climate;

- Appliance ownership;

- Information provided to customers and user interactions more generally; and

- How customers were selected into the experiment.

Moreover, potential load reduction will strongly depend on the extent to which the systems are combined with home automation systems, for example, smart thermostats and load control devices that reduce load when the price exceeds a certain level. Automation can combat potential response fatigue where the customer has to take the decision at each instance of high prices.

Notwithstanding difficulties in comparing across schemes and markets, there is high consistency between the findings of similar studies, which are summarised in the following table.

---

[96] Smart Energy GB, 2015, Is It Time? Consumers and Time of Use Tariff.
[97] See Ahmad Faruqui, 2013, Dynamic Pricing – The bridge to a smart energy future.

Table 10: International Studies on Price-based DR for domestic consumers and SME

Country	Appliance	Study Summary	% of peak load shift	Observation	Source
Time-of-use Tariff					
United Kingdom	Total household load	> Smart-meter trial including 61,344 households (18,370 households with smart meters) > Participants were encouraged to use smart meters through advice, historic and real-time feedback, and incentives to reduce overall consumption	Up to 10 % (higher load shifting on weekends, and for smaller households)	Without smart meters no significant load shifting was observed	EDF and SSE time of use trial, 2011[98]
United Kingdom	Total household load	> Smart-meter trial, including 574 domestic users between Oct 2012- Sep 2013 > Their consumption behaviour was compared to a control group	Electricity consumption during the peak periods 1.5% - 11.3% less than the control group[99]	n/a	CLNR, 2015, Domestic Time of Use tariff[100]
Ireland	Total household load	Smart-Meter Trial including 4,3000 participants (July to December 2009)	Peak usage reduction by 8.8% - 11.3%	Smart-Meters and TOU in combination with bi-monthly bills, energy usage statement and electricity monitor achieved significantly better peak load shifting results	CER, 2011[101]
United Kingdom	Smart appliances, heat pumps and Electrical Vehicles	Modelled scenario for 5 DSR tariff scenarios	10% (2015) to 40% (2030)	n/a	Redpoint Energy and Element Energy, 2012[102]
United Kingdom	Other appliances	Modelled scenario for 5 DSR tariff scenarios	5% (2015) to 20% (2030)	n/a	Redpoint Energy and Element Energy, 2012
Germany – Rheine	Total household load (selected households with high reduction potential)	Smart Meter Trail, including 100 private households. Participants were given specific incentives, including most favourite billing	10%	n/a	Voss et al., 1991[103]
Germany –	Total household load (selected households with	Smart Meter Trail, including over 100 private households. Participants were given specific incentives, including most	12%	n/a	Brand et al., 1990[104]

[98] AECOM for Ofgem, 2011, Energy Demand Research Project
[99] There was no statistically significant reduction in consumption during the single peak half-hour of demand over the whole year.
[100] CLNR, 2015, Insight Report: Domestic Time of Use Tariff – A comparison of the time of use tariff trial to the baseline domestic profile
[101] CER, 2011, "Electricity Smart Metering Customer Behaviour Trials (CBT) Findings Report"
[102] Redpoint energy and element Energy, 2012, Electricity System analysis – future system benefits from selected DSR scenarios
[103] Voss et al., 1991, Lastoptimierung in elektrischen Netzen mit dynamischen Tarifen.
[104] Brand et al., 1990, Freiburger Modellversuche zu neuen Stromtarifen

Country	Appliance	Study Summary	% of peak load shift	Observation	Source
Freiburg	high reduction potential)	favourite billing			
Germany	Total household load	Simulation for households with three part tariff	Weak reaction of consumers: 10% Strong reaction of consumers: 20%	n/a	Ecofys, 2009[105]
International	Total household load	Demand response impacts of 163 pricing treatments that were offered on an experimental or full-scale basis in 34 projects	2%- 13%[106]	Various studies conclude very different results; Price ratios (peak and off-peak) explain a lot of the difference of different studies	Faruqui Arcturus, Sergici (2013)[107]
Time-of-Use tariff (with event pricing)					
United Kingdom	Total household load	Trial on dynamic TOU tariff, including 5,333 customers for smart meter trails and 1,119 customers on TOU	7.1%-11%	Single event reduction increases the peak load shift significantly	Low Carbon London[108]
France	Total household load	> Evidence of implemented scheme. >Private households and SME minimum capacity of 9 kW. > 2008, 350,000 residential and 100,000 small business customers were subscribed to the Tempo tariff. - 300 blue days (standard), 43 white days (medium), 22 red days (high)	> Reduction during medium price period - 15% > Reduction during high price period - 45%	Results may be relatively high due to high consumption of electrical heating	Smart Region, 2013 European Smart Metering Landscape Report 2012- updates May 2013[109]
CPP					
International	Total household load	See above	12% - 38%	See above	Faruqui Arcturus, Sergici, 2013
Australia	Total household load	Trial for Dynamic peak price with peak, including 297 participants, 2006-2008	37%	Incentives for joining (A$100) and completion (A$200)	Integral Energy[110]
CPP with automation					
International	Total household load	See above	14%– 48%	See above	Faruqui Arcturus, Sergici, 2013

[105] Ecofys, 2009, Einführung last-u zeitvariabler Tarife
[106] Not considering the two lowest and highest outliers of the studies
[107] Faruqui Arcturus, Sergici (2013), International Evidence on Dynamic Pricing
[108] Low Carbon London, 2014, Residential Demand side Response for outage management and as an alternative to network reinforcement, Report A1
[109] Smart Region, 2013, European Smart Metering Landscape Report 2012- updates May 2013
[110] As referenced in UK Power Networks, 2014, Residential Demand Side Response for outage management and as an alternative to network reinforcement.

In general, the findings are relatively consistent and show:

- Potential for reduction of overall residential peak demand of 10% (and rising over time) using ToU tariffs, and

- Much higher reductions – of as much as 40-60% of controllable load using RTP/CPP, where this is combined with automation and/or where it refers to new forms of usage, including electric vehicles and heat pumps.

The estimates of the Redpoint Energy study are representative for this sample of studies and are applied in the calculations in this section for the following additional reasons:

- Consistency in calculation methodology with the earlier estimates of the take-up of ToU and CPP tariffs,

- Inclusion of a profile of how the price impact varies over time, and

- Breakdown of ToU impacts by standard appliances and those most susceptible to price based response – namely electric vehicles, heat pumps and smart appliances (rather than all load as per some studies), which appears reasonably consistent with the Gils database.

The key estimates of Redpoint Energy of price based demand response are summarised in the table below.

Table 11: Price based demand response - Redpoint Energy estimates for the UK

Type of tariff	**Scenario**	**2015**	**2020**	**2025**	**2030**
Static ToU	Normal appliances	5%	10%	15%	20%
Static ToU	HP/EV/SA	10%	20%	30%	40%
CPP	HP/EV/SA	30%	40%	50%	60%

Source: Redpoint Energy (2012). Note - Heat Pump (HP), Electric Vehicle (EV), Smart Appliances (SA).

For the purpose of the calculations, these figures have been applied to the relevant controllable load categories identified in the Gils database. It should be stressed that these estimates do not reflect reductions in overall peak demand, but reductions in the controllable demand for the relevant consumption category.

5.3.3 Limitations of the analysis

The analysis includes a number of simplifying assumptions:

- Price based demand response is independent of incentive based demand response. It is quite likely that should smaller customers begin to participate in incentive-based demand response schemes, then their responsiveness to price based incentives will increase.

- Tariff structures are not taken into account. In practice, the extent to which customers will change behaviour will be influenced by the relative proportions of fixed and variable charges on its bill – including in the network component. As average values from international studies have been applied it is unclear whether this assumption is conservative or potentially overstates the response at an EU level as a whole.

5.4 Incentive based demand response

Section 5.4 comprises an assessment of the incentive based demand response. Similar to the previous section on the price based demand response, the section presents an estimate of the current level of incentive based demand response following by assessment of how the policy options could change the level. The sub-sections include the following:

- Assessment of the current level of incentive based DR
- The EU target model compared to other market models
- Measures to increase incentive-based DR
- Approach to estimate the effects of the options
- Links between price and incentive based DR

5.4.1 Assessment of the current level of incentive based DR

While EU Member States which took a decision to enable Incentive-based Demand Response in 2013-14 have made significant progress, other Member States are still undergoing regulatory reviews or have decided against making any significant changes at this time. Belgium, Finland UK and France have reached a level where incentive-based Demand Response is a commercially viable product.

We are presenting the status for incentive based demand response in MS in three areas: participation in wholesale markets, balancing markets and capacity markets. Mechanisms for grid management purposes are not included as they, for MS states where such mechanisms are allowed, may vary between different utilities.

Incentive based demand response in wholesale energy markets

Most MS have established wholesale markets for energy, but there are still some countries without well-functioning wholesale energy markets.

In most MS with day-ahead and intraday markets established, the demand side is allowed to participate, represented by the BRP. Due to the target model for the markets and the BRPs having a responsibility for scheduling their demand, in most MS only BRP may place bids in the market. France is the only MS allowing bids from non-BRP. Therefore, mainly large industrial consumers are proactive in the markets, placing price sensitive energy bids in day-ahead markets and doing rescheduling in the intraday market.

Demand response in the day-ahead market will be represented by price dependent bids (volume of demand bid depending on the settled day-ahead price) by BRP..

Trading from the demand side in the intraday market could either reflect demand side flexibility or a need to change positions due to changes in needs (regardless of energy price levels). We have summarised in which markets the demand side is allowed to participate in the wholesale market in the table below. In addition, we have checked the level of price-sensitive bids for selected hours in different markets.

Naturally, the level of participation in the markets will depend on the risk the BRP faces by not being active. If electricity prices are volatile and consumers/BRPs face the risk of frequent price peaks, they will have an incentive to lower this risk by placing price depending bids. Price caps in the markets lower this risk. Also, the levels of penalties when scheduled volumes are not met, will influence the incentives to reschedule energy demands during the hours before market closure.

Table 12: DS allowed to participate in wholesale energy markets in MS

Member State	**Day – ahead**	**Intra-day**	**Comments**
Austria	X		DS participation is allowed
Belgium	X	X	DS participation is allowed, but only a few large industrial players are active.
Bulgaria			No DS participation and not a well-function market.
Croatia			No DS participation. Plans of launching DA and ID market in 2016.
Cyprus	-	-	No wholesale markets exist
Czech Republic	X	X	Bids only from BRP, only large consumers are active
Denmark	X	X	Bids only from BRP
Estonia			Bids only from BRP, DS participation unclear
Finland	X	X	Bids only from BRP, large consumers are active
France	X	X	Bids accepted from non-BRPs. 1,5 GWH from non-BRP in 2015
Germany	X		DS participation is allowed in DA, but only large consumers are active
Greece			DS participation is not allowed. Price caps have been removed.
Hungary	X	X	DR from large consumers and aggregators take place
Ireland	X	X	DR participation by bidding and dispatch. NO BRP, energy is settled ex-post.
Italy	X		Bids only from BRP, increasing DS participation.
Latvia	X		DS is allowed in the wholesale market (unclear which markets they have)
Lithuania			Low competition and unclear whether DR takes place at all
Luxembourg			No information
Malta	-	-	No wholesale markets exists
Netherlands	X	X	Bids only from BRP
Poland	X	X	Bids only from BRP, low activity
Portugal	X	X	DS participation is allowed (BRP), but low level of participation. Price cap on electricity.
Romania	X	X	All trade must take place in the market places. DS and aggregators are allowed, but no activity.
Slovakia	X	X	DS participation (with licence) is allowed. Only large consumers are active
Slovenia			DS participation is not allowed
Spain	X	X	Bids only from BRP, level of participation is not known.
Sweden	X	X	Bids only from BRP, large consumers are active
UK	X	X	Bids only from BRP, limited DS participation.

Sources: The on-going work of JRC (2016), Entso-E (2016), THEMA (2016) and SEDC (2015)

A few MS do not have wholesale energy markets in place (Cyprus, Malta) and some MS do not have well-functioning markets in terms of competition on the generation side and/ or supplier side.

In MS where there are established wholesale energy markets, the demand side participation is mainly from large, industrial players. The main reason for this is a general requirement for participants to be BRP. In most markets, the level of DR in the wholesale markets is considered to be low. This may be explained by low price variations and price caps in the markets or by various restrictions and barriers in the markets. Moreover, the share of total energy traded in the wholesale markets varies between MS, and low volumes traded overall may be one explanation for low DS participation in these markets.

The Greek electricity market is undergoing significant design and structural changes, which are expected to include among other things: the introduction of an intraday market (possibly by end 2017) and the introduction of forward trading,

Belgium is one of the MS where the demand side (BRP) may place price sensitive bids in the wholesale energy markets. However, the share of the electricity traded on the spot markets are low in comparison with the total market as retailers tend to make agreements with generators, who they may also own (JRC, 2016).

In France, aggregators traded 1,5 GWh in the day-ahead and intraday markets in 2015 (Entso-E, 2016). There are currently 10 independent aggregators operating in the market and there is regulation in place describing settlement between the retailer (BRP) and the aggregator.

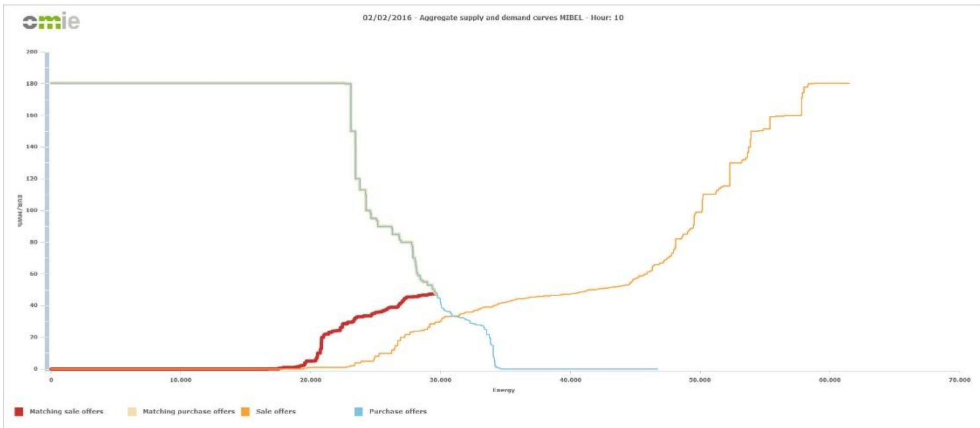
In Italy during 2013, the demand side placed price sensitive bids for 47 TWh out of 230 TWh being traded in the spot markets (SEDC, 2015). This indicates that 20 percent of the traded volumes was flexible. However, only 5,9 TWh of these bids were accepted, representing a utilised level of DR of 2,6 percent of the traded volumes. It is however unclear how this corresponds to reductions of the peak load for Italy.

To illustrate some signs of DR taking place within the Day-ahead market, we have checked the demand curve for three market places representing five MS. The figures below show the price sensititvity in demand bids for the Iberian, German/Austrian and French markets during the 2nd of February 2016 for the hour 9-10 in the morning. The curves show that consumption would have been 5000 MWh , 3360 MWh and 250 MWh and lower for that hour in Spain/Portugal, Germany/Austria andFrance if prices had risen to a level of 100 EUR/MWh from 40, 22 and 32 EUR/ MWh, respectively.

Such demand reduction represents 12 % of peak load in Spain and Portugal, 4 % of the sum of German and Austrial peak load and 0.3 % of peak load in France..

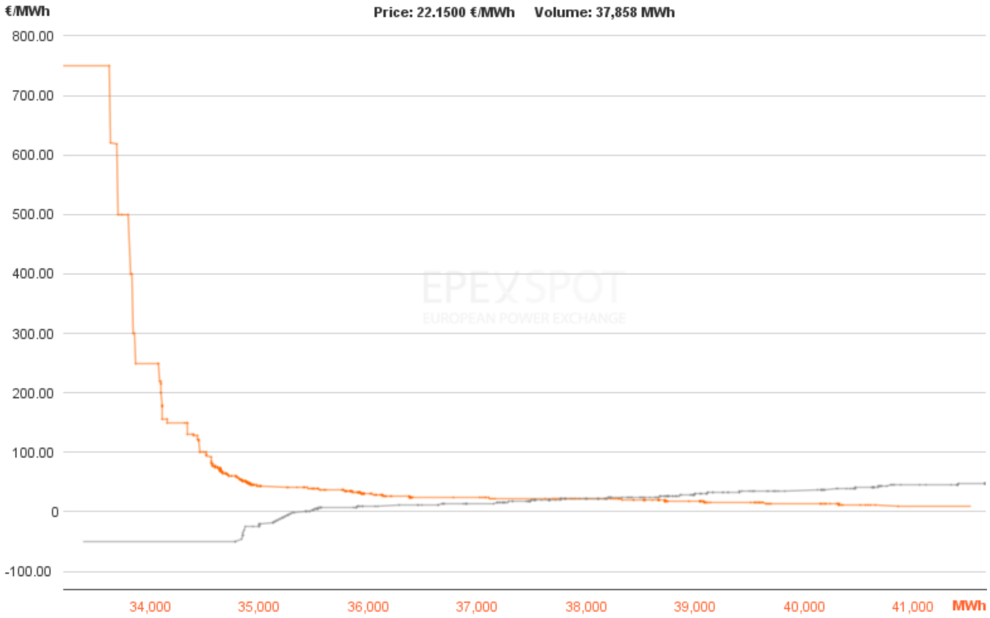
Please note that some volumes on the demand side may represent industial players starting their own generation instead of buying electricity from the market. To determine a more precise estimate of DR in the energy wholesale markets, in-depth studies of the underlying data for the demand and supply curves are required, including demand and generation types in the MS. This is outside the scope of this study.

Figure 8 Demand/ supply curve for the Iberian market 2nd of February 2016, hour 10



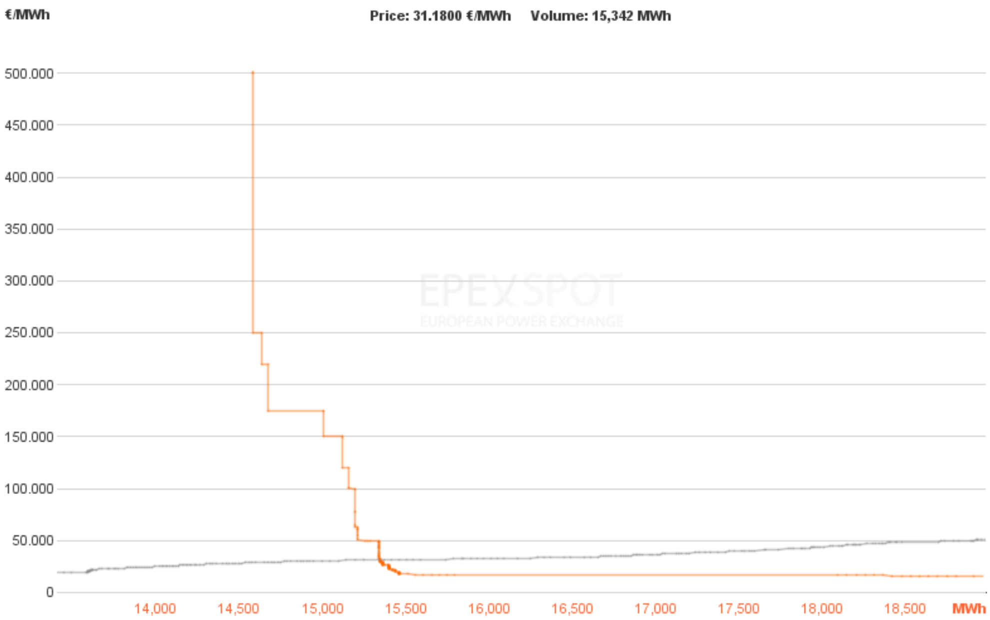
Source: OMIE (online)

Figure 9 Demand/ supply curves for the German/Austrian market 2nd of February 2016, hour 10



Source: Epex spot (online)

Figure 10 Demand/ supply curves for the French market 2nd of February 2016

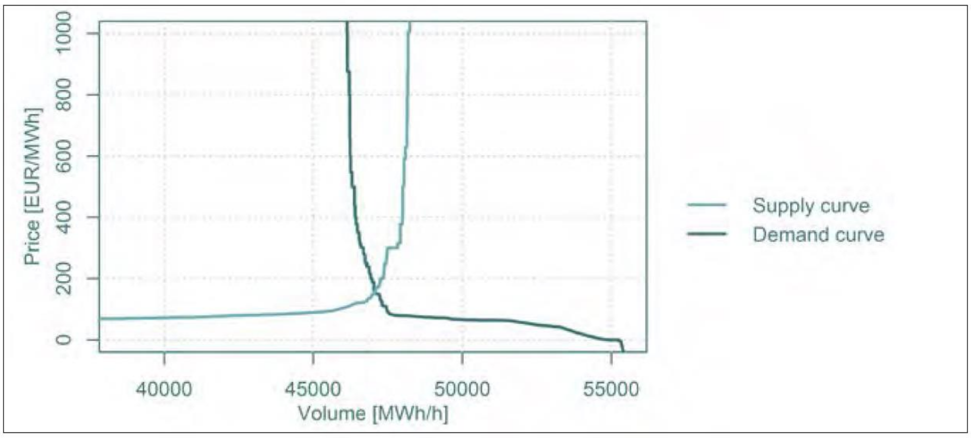


Source: Epex spot (online)

From Nord Pool Spot, we have examples of price sensitive bids in high-price periods when the price sensitivity is assumed to be at its highest. THEMA (2015) describes the price sensitive bids from the demand side for one hour in 2010 and one hour in 2015 in the day-ahead market. For 2010 and 2015, respectively, 83 and 89 per cent of the bids, were not price-sensitive. Hence, 17 and 11 per cent of the bidding represented DR for these two hours. The price-insensitive bids are probably from power intensive industry, but also some from pumped hydro. The total flexible volume in the 2015 hour was 6 870 MW, of which about 2 300 MW were above the system price (53.57 EUR/MWh). Note that parts of the demand flexibility in the low price region (particularly at or below zero) represents pumped hydro, which buys electricity at low prices. Moreover, the majority of the observed demand response is available below prices of 100 EUR/MWh. The numbers presented here only show single hourly bids. Other types of (more complicated) bids are not included, thus there may be additional demand response available that is not observable in these numbers.

The reduced demand (2 300 MW) due to prices above the placed bid for the 2015 hour represents 3.2 percent of the peak load for the Nordics in the winter of 2014/2015 (71 500 MW), whereas the total flexible demand bids represent 9.6 percent.

Figure 11 *Market cross for the Nordic day-ahead system price 15th of December 2015 for the hour 18-19*



Source: THEMA (2015 based on numbers from Nord Pool Spot)

When demand is faced with risk of high electricity prices, and are allowed to bid into the wholesale energy markets, one should expect price sensitive bids up to the level of 10 to 18 percent as seen in high price periods in the Nordics and the Iberian market.

Incentive based demand response in balancing markets

There are often strict requirements to participate in balancing markets. For some products, the activation time is very short, volumes high and there may be a short resting time between activation. Some MS have adjusted requirements for the demand side to increase participation in these markets and consequently to ensure sufficient capacity. The main volumes are offered by large industries.

In France, Belgium, UK and the Nordics the demand side plays an active role in balancing markets. In Belgium and France aggregators are also active, either through bilateral contracts with the BRP, operating within a standard framework (France) or in specific products where the normal market rules ensures compensation for the BRP (JRC, 2016 and SEDC, 2015). In the Nordics and in Belgium there is also some aggregation from suppliers offering aggregation to their customers and placing common bids within their BRP.

Table 13 *DS allowed to participate in balancing markets in MS (volumes in MW where available)*

MS	**FCR**	**FFR**	**RR**	**Other**	**Comments**
Austria	No	Yes	Yes		
Belgium	27	321			FFR from 2014, FCR from 2016 Bilateral contracts with the BRP for the interruptible loads.
Bulgaria	No	No	No		
Croatia	No	No	No		Mandatory participation from generators
Cyprus	-	-	-		There are no such markets
Czech Republic	No	No	Yes		DS can only participate in RR
Denmark	23	555	Yes		Nordic market for primary and tertiary reserves. Mainly from electric boilers in district heating
Estonia	No	No	No		Most participants from outside Estonia, FCR

MS	FCR	FFR	RR	Other	Comments
					provided by Russia
Finland	100	Max 300	40		Nordic market for primary and tertiary reserves.
France	60	160	1800		Test phase for DSR participation of 1800 DR in RR
Germany	Yes	Yes	Yes		Low DS participation in balancing markets. Interruptible loads programme for large consumers
Greece	No	No	No		BEM will be included in new market design.
Hungary	No	No	Yes		DS can only participate in RR
Ireland	No	No	No	Yes	Interruptible contracts for industrial sites used as short term reserves for the TSO
Italy	No	No	No		DS not allowed to participate.
Latvia	No	No	No		DSR not allowed to participate (FCR provided by Russia)
Lithuania	No	No	No		DSR not allowed to participate (FCR provided by Russia)
Luxembourg					No information
Malta	-	-	-		Such markets do not exist
Netherlands	No	Yes	Yes		
Poland	Yes	Yes	Yes		DSR does not participate on equal basis as thermal plants. No DS participation.
Portugal	No	No	No		DS not allowed to participate.
Romania	Yes	Yes	Yes		DSR does not participate on equal basis as generation, participation is low
Slovakia	No	No	YEs		DS can only participate in RR, bilateral contracts for large industries with TSO or DSO
Slovenia	20				
Spain	No	No	No		DS not allowed to participate. DR only from large interruptible loads
Sweden	Yes	10	626		Nordic market for primary and tertiary reserves.
UK	374	Yes	1260	Yes	(2015) DR-RR is established for large consumers to reduce demand during winter weekdays btw 4 and 8 PM

Sources: The on-going work of JRC (2016), Entso-E (2016), THEMA (2016), SEDC (2015) and TSOs websites

Barriers usually stem from programme participation requirements, which are not yet accommodated to cater for demand-side resources. For example, in Austria a consumer may be required to install a secured and dedicated telephone line to participate in the balancing market. In Norway, TSO signals are still delivered over the telephone, and therefore the minimum bid-size remains high. Rules such as these block the participation of all but the very largest industrial consumers. However, the minimum volume for bidding in balancing markets has been lowered to 0.5 MW in Belgium and from 10 to 5 MW in the Nordics to attract more bids. According to Fingrid (fingrid.fi), loads from large-scale industry have, for a long time, acted as reserves used for maintaining the power balance in Finland. Demand-side management is a natural opportunity to increase supply on both regulating power and reserve markets.

A lack of clarity around roles and responsibilities may also constitute barriers for new entrants. For example, Germany, Poland and Slovenia lack a viable regulatory framework for measurement, verification, prequalification and/or competition between service providers, have complex, generation centred programme requirements, and/or even network fees designed to incentivise a flat consumption pattern, and hence penalise those who provide flexibility to the system.

According to Entso-E (2016) DR provide 10 per cent of FCR resources and 16 per cent of mFRR capacities in France (60 and 160 MW respectively).

Great Britain has a highly competitive energy market and balancing markets are open to demand-side bidding, but, according to SEDC, the future of incentive-based Demand Response in the country has become more difficult due to the launching of the GB Capacity Market[111]. The short term operating reserve (STOR) is the main market for DR in the UK. According to Curtis (2015) the resources are awarded by tenders and the awards for these resources started at 40/50.000 £/MW in 2007, peaked at 60/70.000 £/MW in 2012 and have decreased to 20/30.000 £/MW in 2015. Minimum levels are 3 MW and volumes may be aggregated. Disconnections may last up to 2 hours and activation time may be up to 20 minutes. The main volume of flexibility (>80 per cent) is provided by consumers having back-up generation on site.

The new Greek market design, passed in May 2016, includes a balancing market. Also the TSO will be separated from the main power utility in Greece, PPE, and partly privatised in the process (energypress.eu, 2016).

Capacity mechanisms

UK and Italy are the only MS with an established capacity market and France is planning for market opening in 2017. When it comes to capacity mechanisms, general experience is hard to extract as the schemes come in a large array of different designs, and several capacity mechanisms are not open to demand-side participation. We give an overview of some examples below.

It should however also be noted that the design of Capacity mechanisms varies substantially between MS, although the outcome of the ongoing sector inquiry and the pending revision of guidelines, may be that the design features are harmonized to a larger extent.

Table 14 DS participation in capacity mechanisms in MS (volumes in MW where available)

MS	**Mechanism**	**DS Volume**	**DS participation**
Austria			
Belgium	Strategic reserve	358	2015-2016 (elia.be)
Bulgaria			Over-capacity and no need for capacity mechanisms
Croatia			
Cyprus			
Czech Republic			
Denmark	No strategic reserve/ CM		
Estonia	No capacity market		
Finland	Strategic reserve	10	
France	Capacity market – DS only		Capacity market to start in 2017 including DS participation

111 http://www.smartenergydemand.eu/wp-content/uploads/2015/10/Mapping-Demand-Response-in-Europe-Today-2015.pdf

Germany	Interruptible load programme	694	Discussions on Capacity market, most likely not including DR
Greece	Interruptible load program Planning for capacity mechanism	1500	Interruptible loads program from 2016 – consumers > 5MW
Hungary			
Ireland	Fixed price per half hour through the year linked to the energy market		Open to all, but with high requirements to participate. New capacity market planned to include DS.
Italy	Capacity market Interruptible loads	4061	Volume from interruptible loads from large industry (>1 MW). Exploring to include DS in capacity mechanism
Latvia	Capacity market		DS included
Lithuania			
Luxembourg			
Malta	No capacity market		
Netherlands			
Poland	Capacity reserves		Generation only
Portugal			
Romania			
Slovakia			
Slovenia	No Capacity market		
Spain	Capacity mechanism Interruptible loads	2050	Generation only in the CM. Volumes from interruptible loads
Sweden	Strategic reserves	626	The volume represents 42 per cent DR of total participation (2015)
UK	Capacity market	174	Open to DS, but low participation

Sources: The on-going work of JRC (2016), Entso-E (2016), THEMA (2016), SEDC (2015),and TSOs websites

Experience from the GB capacity auctions held so far, does not indicate a high share of DR participation. For the year 2018 a volume of 49 GW was contracted, of which 174 MW from demand (0,35 per cent). The reason may be that 1) the capacity price realized in the GB auction was relatively low (much lower than expected), and/or 2) that the product definitions are not attractive for demand response.

In France a capacity market will be established from 2017. This will be a decentralised market that obliges the retailers to by capacity certificates up to the peak in their portfolio. This program is restricted to the demand side (JRC, 2016).

Finland, Sweden and Belgium have strategic reserves open to participation from the demand side. According to THEMA (2015) a significant share of the peak-load reserve consists of demand response in Sweden. The original plan was to gradually phase out all of the generation capacity from the strategic reserve to 2020, resulting in a reserve that consisted entirely of demand response. However, in reality it turned out to be challenging to achieve the target. In 2015 there was 626 MW (42 per cent) of consumption in the Swedish PLR. SvK states that the requirements for participation, such as continuous readiness and long-term commitment, is a barrier to increase the share of demand response in the reserve. The plan to phase out all generation capacity was therefore renounced. For DR participating in the reserve, the obligation is to keep consumption under a specified maximum level during stress situations, defined as situations the DAM algorithm is not able to establish an equilibrium between supply and demand based on market bids (and nominations), and/or the TSO is unable to secure sufficient reserves. Contrary to generation in the peak load reserve, demand side resources are obliged to be active in the market.

The load can either provide their flexibility as a price-sensitive bid in the DAM, or as a bid in the reserve market.

Both Italy and Spain utilize a substantial level of DR through interruptible load contracts for large industrial consumers. In Spain this programme acts as an emergency action in case the system lacks sufficient generation and balancing resources. However, the programme has not been activated in many years, and this has raised a question whether this programme is promoted to enhance DR or is in fact a disguised subsidy to the national industry (JRC, 2016). In the case of Italy, it is unclear if the interruptible loads have ever been activated, even though the payments are attractive and related mostly to the availability of volumes and not to activation (JRC, 2016).

In Greece, the “disruption management” plan offers major industrial enterprises electricity cost savings in exchange for shifting energy usage to off-peak hours whenever required by the operator. The total annual sum to be offered by the plan through auctions will be about EUR 48 million. Initial pilot auctions, one covering longer-term agreements and the other short-term agreements for the month of March was held at the end of February 2016. Subsequently, the second round of auctions held at the end of March and covering April 1 to 30, increased the electricity amounts offered to 650 MW for short-term agreements and 850 MW for longer-term agreements (both up from 500 MW each in the first auction) to meet increased demand expressed in the first auction and satisfy participant needs.

Summary

The table below summarize the amount of incentive based DR found and estimated in the MS. DS are allowed to participate in several MS, so there may be more volumes represented in balancing and capacity markets, but levels are indicated to be low. See BAU in section 5.5.2 for methodology on estimated levels for incentive based DR in MS where no volumes have been found in the literature.

Table 15 Incentive based DR

MS	**DSP in energy markets**	**DSP in balancing markets**	**DSP in capacity mechanisms**	**Estimated BAU for 2016**
Austria	Yes	Yes		104
Belgium	Yes	Yes	Yes	689
Bulgaria	No	No		0
Croatia	No	No		0
Cyprus	No market	No market		0
Czech Republic	Yes	Yes		49
Denmark	Yes	Yes		566
Estonia	Yes	No		0
Finland	Yes	Yes	Yes	810
France	Yes	Yes	Yes	1689
Germany	Yes	Yes	Yes	860
Greece	No (2015)	No		1527
Hungary	Yes	Yes		30
Ireland	Yes	Yes	Yes	48
Italy	Yes	No	Yes	4131
Latvia	Yes	No	Yes	7
Lithuania	unclear	No		0
Luxembourg	No information	No information		

MS	DSP in energy markets	DSP in balancing markets	DSP in capacity mechanisms	Estimated BAU for 2016
Malta	No market	No market		
Netherlands	Yes	Yes		170
Poland	Yes	Yes	No	228
Portugal	Yes	No		40
Romania	Yes	Yes		79
Slovakia	Yes	Yes		40
Slovenia	No	Yes		21
Spain	Yes	No	Yes	2083
Sweden	Yes	Yes	Yes	666
UK	Yes	Yes	Yes	1792
Total				**15628**

As shown in Section 1.2.1, DR is participating in the wholesale energy markets in many MS. The level of demand response (in terms of price-sensitive bids) will vary over time depending on price levels and price volatility and are not represented in the table. The energy markets may represent the highest DR volumes from incentive based DR, and has been proved to represent over 10 per cent of peak load in the Nordic markets in terms of volumes of price sensitive bids in high price periods with high risk of price peaks. In periods with low prices and low risk of price peaks, the price sensitive bids may be less than 1 per cent as shown for the German/Austrian, French and Spanish/Portuguese markets. The DR in the wholesale markets will be very dependent on specific conditions in each MS.

The actual volumes we found in literature for DR volumes is about 15 GW (data from 12 Member States). We have included conservative estimates for Member States that allow incentive based DR but where there is no directly available data on volumes. One could argue that the volumes are not active in the markets as some volumes are rarely activated (i.e. volumes for Italy and Spain). This is true – but volumes are there, but the market design allows inefficiencies in DR mechanisms – and that is a different discussion. On the other hand – this is an argument that volumes may be reduced when efficient use is taking place – i.e. that the volumes in Greece, Italy and Spain will be reduced if DR will participate in a level playing field

5.4.2 The EU target model compared to other market models

The observed level of DR in the EU MS are often compared with levels found in other markets, mainly markets in the US. This comparison should be done with great care, as a number of important market design features differ between US and European markets. In most markets there are a combination of energy markets, markets for balancing services and capacity mechanisms of some sort. To categorise different market set-ups relevant for DR, the most important elements are:

- Whether there is a “demand curve” based on bids from demand or if there is a central schedule and dispatch (done by the system operator)

- Whether the main investment incentives are based on energy or capacity remuneration

The EU target model is energy-only and the market participants, including the demand side, place bids and offers to establish the operating schedule. The market design implies that the real-time balance is achieved step-wise:

1. Forward markets signal long-term prices to which supply and demand may adjust
2. Day-ahead market bids and offers represent the ability and costs associated with different levels of supply and demand
3. The intraday market offers opportunities to handle deviations from the day-ahead market solution due to forecast errors and contingencies that appear after gate closure in the day-ahead market and prior to gate closure in the intraday market
4. TSOs manage real-time (within the hour) deviations due to within the hour variations (structural imbalances) and forecast errors and contingencies not handled in the intraday market.

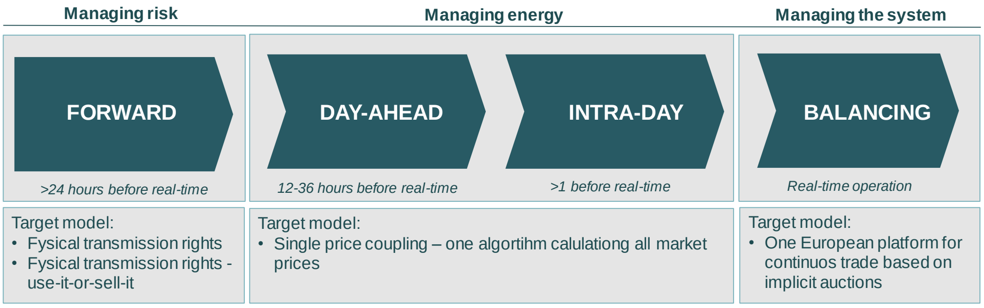
The day-ahead market is in essence a forward market (albeit short term), and deviations from the day-ahead market solution will occur in real-time. Such deviations may be handled by market agents' trading in the intraday market, or by the TSO in real-time. Forecast errors may appear and contingencies occur at any time between closure of the day-ahead market and real-time.

However, even if the market agents handle all deviations from the hourly day-ahead market solution in the intraday market, the TSO needs access to balancing reserves. The reason for this is that the day-ahead market operates as if demand (and supply) is stable within each hour, which it is not. In order to handle planned and unplanned deviations in real-time, the TSOs must have access to reserves for balancing within the hour.

TSOs has to procure reserves for real-time balancing in order to manage imbalances and bottlenecks, incidents and disturbances during the operation hour. Even if BRPs do not deviate from the day-ahead/intraday plan, their generation and/or consumption is not constant within the hour. The TSOs are responsible for the within the hour system balance. To this end TSOs purchase different kinds of balancing reserves, including manual restoration reserves used to manage congestions and imbalances, and automatic reserves used to ensure system security (frequency) and to manage imbalances. The DR activated in balancing markets may be described as *reactive* as these mechanisms respond to unwanted (but sometimes inevitable) deviations from schedule.

It is important to note that neither form of Demand Response is a replacement for the other. Even if most DR takes place in the energy markets, there will always be deviations from schedule that needs to be handled real time. And there may also be local DSO markets for flexibility not covered by the wholesale markets.

Figure 5-12: The EU target model for electricity markets



The energy markets' timeframe is up until gate closure 1 hour before real time. Loads participating in the balancing markets will be dispatched by the system operator according to their bids (and location), or may be notified to curtail loads within a defined (short) time frame.

In addition to the electricity markets, some MS have some sort of capacity mechanisms in place, while others have implemented or are planning to implement capacity markets to ensure long term capacity adequacy.

The bids in energy markets provide a baseline, while a baseline is administratively set in the US markets

As stated earlier in this report, US markets have provided substantial levels of DR. Before we look into different policies to increase DR in MS, it may be interesting to take a closer look at the differences and similarities between the US markets and the target model for the integrated EU energy market. It is important to notice the difference in the role of the TSO, both in the scheduling and during the operating hour in the target model versus in the US markets and also how the energy market influences this role.

One purpose of the energy markets is to prevent and limit imbalances in the operation phase, and may therefore be seen as *proactive* DR. In practical terms, the day-ahead market solution (including nominated supply and demand) means setting a baseline for the demand and generation for the operating hour and participation is mandatory for both demand and supply in the form of balance responsible parties (BRPs). BRPs are penalized if they do not adhere to the plan in real-time (imbalances), unless they have managed (foreseen) imbalances in the intraday market. Hence, the balance responsibility creates an incentive to handle imbalances as soon as they become known. By placing bids in the energy markets, the demand side also participate in the price formation, and may help prevent price peaks.

The schedules for each market participant serve as a starting point for the TSO in operation of the real time balancing of the system. The schedule from each market participant also sets a baseline for the energy consumption if bids in balancing markets are not activated. This baseline is helpful when settling imbalances and rewards for activation.

The mandatory participation in scheduling real-time operation gives the BRPs a responsibility not to deviate from schedule and the risk of penalties if they do so.

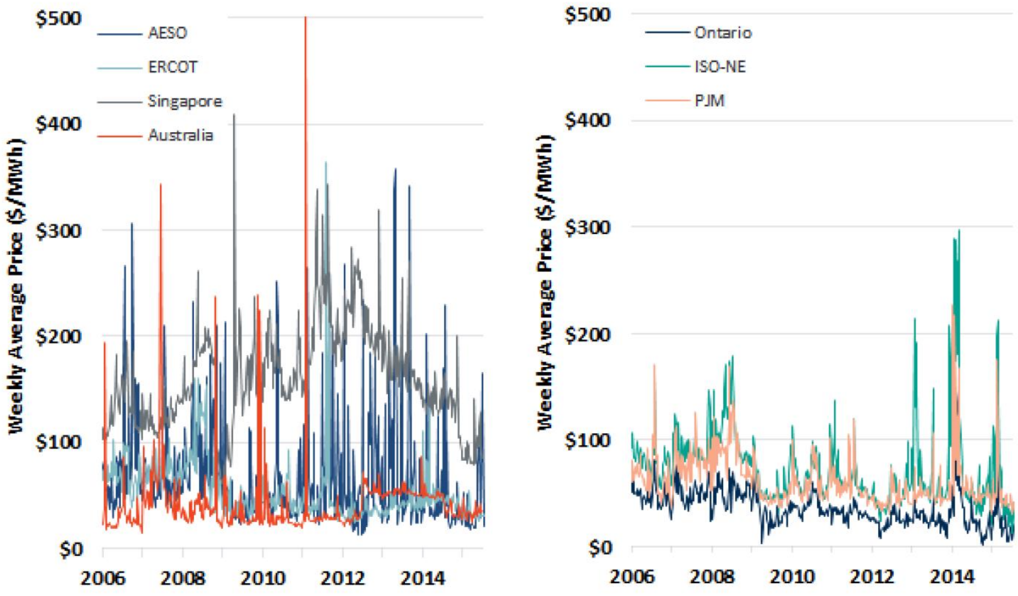
This is not the case in the US markets, as the demand side at best is allowed to place bids. In the US-markets the operating schedule is set by the TSO and there is therefore no issue of imbalances or risk for the BRP in the case of independent aggregators providing DR. Suppliers are settled on the basis of metered load and have no up-front energy position. However, this approach raises questions regarding the "business-as-usual" load that would have been consumed if it had not been activated. Such a baseline is needed as a basis to verify and settle energy and the level of DR activated. There are different ways of establishing a baseline for loads that are active in the markets. It is important that the approach for establishing a baseline avoids the opportunity for gaming, i.e. the possibility to increase the baseline before activation to increase the reward of activation (which is often the difference between the baseline and the actual metered load). Manipulation of the baseline has been discovered, and penalized, in the US markets (Brattle, 2015).

In energy-only markets the main incentive for DR is variable energy prices

In several of the US markets often referred to when discussing DR, the market design is fundamentally different for the EU target model. In PJM, ISO-NE (combined with a day-ahead market) and Ontario the main incentive for investments is capacity. In all of these examples it is voluntarily for the demand side to place bids in the day-ahead markets. However, the price peaks are more frequent in energy only markets compared to capacity based markets, and price variations are the main incentive for the demand side to be active in these markets.

In a capacity based market design, the price variations of energy are generally lower than in energy-only markets. Hence, the incentive for DR in energy markets are significantly higher in energy-only markets (like the EU target model) than it is in capacity markets. Implementing capacity markets in MS will to some extent, depending on the actual design, reduce price variations in the energy markets and thereby reduce incentives for DR in energy markets.

Figure 5-13: Weekly-average energy prices in Energy-Only markets (left) and Capacity markets (right) (prices in AUD/MWh)



Source: AECM (2015)

Penalties for imbalances provides extra incentives for DR

A BRP that deviates from his spot market commitments is penalised by an imbalance cost. This penalty is paid to the TSO who incurs costs in order to handle the residual imbalance.

If the cost of energy in the balancing market is the same as the actual payment for the energy, this will be a zero-sum game for everyone involved and there is no incentive for the BRP to stay in balance. However, the cost of energy bought, prices in the energy markets and prices in the balancing markets may not be the same:

- The supplier may have bought energy as part of a portfolio and in a long time frame instead of buying the energy in the DA market. If compensation for energy volumes is based on DA-prices this may result in compensation to the supplier being higher or lower than the energy price in balancing markets
- According to the NC for balancing suggested by Acer, the TSO will set the prices for imbalances. Imbalance price for shortage should represent at least the weighted average price of FRR and RR reserves needed to restore balance. For surplus on the other hand, the price of activating FRR and RR is the upper limit for imbalance prices. The merit order curve for these markets are not the same as for energy markets, and prices will most likely be higher.

As long as it is cheaper to ensure balancing in the intraday market than in the imbalance settlement, the balancing responsibility yields an incentive to place bids and nominations as accurately as possible, and to manage imbalances in the intraday market.

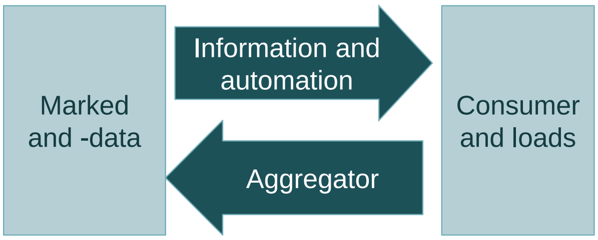
Incentive-based demand reduction in the wholesale energy markets helps reduce imbalances in the operating hour by improving the planning of supply and demand ahead of the operating hour, thereby improving price formation and reducing the need for balancing reserves. In addition, flexible DR can also help manage imbalances in the operating hour, e.g. in the form of interruptible loads.

The main advantage of including both the generation side and the demand side in wholesale price formation is to minimize unforeseen imbalances in the operating hours. Handling of imbalances in real-time is in general both riskier and costlier for the system. The costs are higher because the costs of provision (of flexibility) are higher when notification is short, and all flexibility resources are not able to react on very short notice. Thus, the barrier for the demand side to participate is lower in the day-ahead and the intraday markets since the notification time is longer (ahead of real-time). Moreover, price formation becomes more efficient with participation of DR, as price sensitive bids in the day-ahead or intraday markets should reveal the available volumes of flexibility and the associated cost of DR.

5.4.3 The role of aggregators in the wholesale energy and balancing markets

As opposed to service providers and technology that helps the consumers respond to price signals in the market (and thereby bringing the market to the loads, see the figure below), the aggregator acts as an intermediate between the consumer and the different market participants procuring flexibility . The energy markets are complicated for most users and even industrial consumers may use service providers or suppliers to nominate loads in day-ahead and intraday markets, and to sell flexibility in balancing markets. Service providers may help commercial and industrial consumers to better understand the markets and to adjust to markets to save costs. Such services will mainly be price-based by providing market data and automation to help adjust loads according to price signals.

Figure 5-14: Service providers enabling demand response



Below we discuss four different models for aggregated DR in the markets:

- The suppliers integrate aggregated DR as part of their service offering
- The aggregator and supplier must bilaterally settle imbalances and costs
- The aggregator must take on a second balance responsibility for activated loads

- The aggregator operates independently of balance responsibility and without compensation

The supplier offering aggregated DR

In essence, suppliers may take advantage of, or offer, aggregated DR in the sense that, in addition to supplying electricity and taking on the balance responsibility for their customer portfolio, the supplier may integrate a DR service comprising all or some consumers in their portfolio as illustrated in the figure below. By doing so, the supplier may submit price-sensitive bids in the wholesale market, provide flexible volumes to the intra-day market, and improve their own balance, thereby reducing the cost of imbalances. If imbalance costs are high, this approach may be attractive for suppliers. The supplier/ aggregator may also provide DR to balancing markets and local markets for flexibility to the DSO. When the flexibility products are priced differently, the supplier may optimize the use of DR across the different flexibility markets.

An advantage of this setup, according to Enfo Energy (2014), is the integration between the financial and physical power markets, without altering the main market rules in the EU target model.

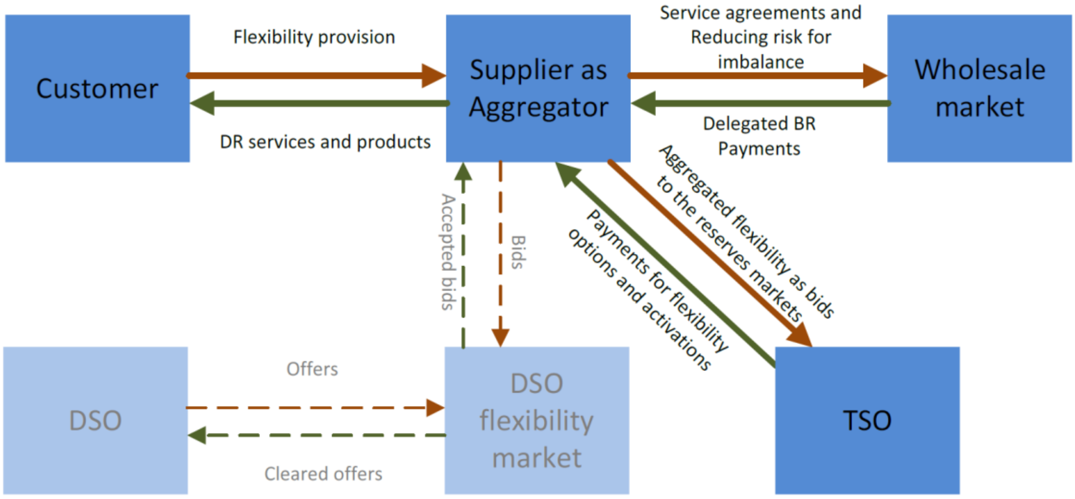
In a well-functioning market, one would think that suppliers would be interested in aggregation, either on their own accord or via external aggregator (service providers). In a competitive market where the consumers are interested in providing incentive based DR, adding aggregated DR to the service offering will be necessary to keep market share. This will only be valid if the consumer is able to change supplier at a very low cost.

Aggregation (and energy management) of flexible loads is a different business than retail electricity provision, this may serve as a barrier for suppliers to enter into aggregation (at least without service providers). Moreover, retail electricity sale is an economies of scale business, and it may take time to build a sufficient customer base for aggregators to take on the role of electricity suppliers.

On the other hand, this kind of setup may cause consumer lock-in. To avoid lock-in effects, there should be several suppliers offering aggregated DR in the market. Reducing barriers to enter the retail market may therefore be one essential task in order to encourage efficient retail aggregation.

NordREG, the cooperation body of the Nordic electricity regulators, recommends that only suppliers should be allowed to offer aggregated DR in mature and well-functioning markets as the Nordic (NorREG, 2016). Also in Belgium, the TSO states that all markets are open to the aggregated bids as long as they are handled by the supplier (JRC, 2016).

Figure 5-15: The supplier as an aggregator



Source: Enfo Energy AS and The Norwegian Smart Grid Centre (2014)

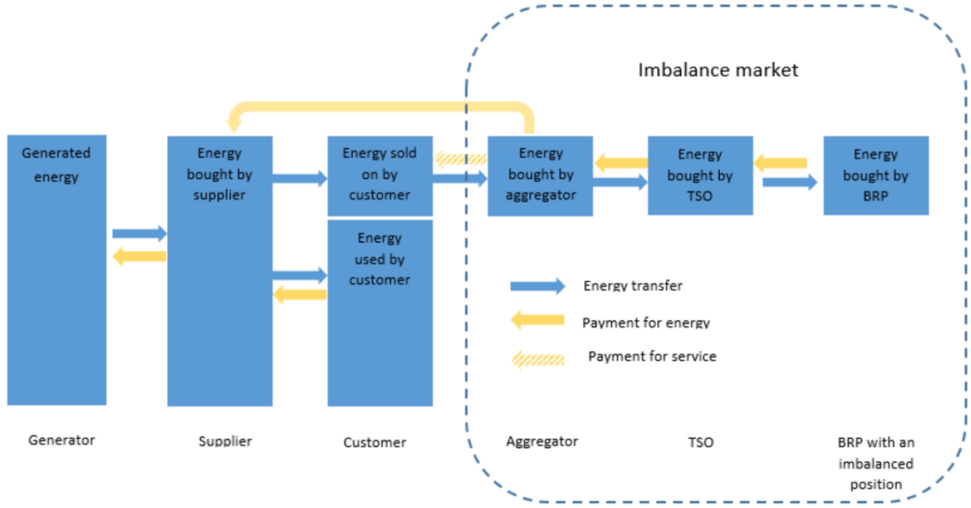
Independent aggregators compensating BRPs

Aggregators and suppliers may act independently of each other in the markets, and settle the costs of energy and imbalances after activation of bids. The settlement process could either be based on bilateral agreements between aggregators and suppliers or be subject of regulated standard agreements. In the first case, the suppliers will have the power to keep aggregators out of the markets if they do not see any benefits for themselves in entering into an agreement. Standard agreements could make aggregators able to enter the market without the consent from suppliers and remove this barrier for aggregated DR. Regulated standard agreements will contain regulated prices for costs of imbalances and energy that may not correctly represent the cost of the supplier.

In order for this solution to be interesting for aggregators, the value of bids in the markets must be higher than the BRP' cost of imbalances caused by the DR, or else there will be no revenue to split between the aggregator and the consumer after compensating the supplier. This depends on how the penalties for imbalances are set up and the TSOs cost of balancing.

The case of load reductions by an independent aggregator is shown in Figure 5-16. The principle will be the same if there is no aggregator and supplier involved, except that the consumers handle the flow of energy and payments themselves (i.e. large industries).

Figure 5-16: Energy and payment flows when an independent aggregator curtails a load



Source: Baker et. Al (2015)

In this model, as in the markets in the US, there will be an issue of setting up a baseline for the activated loads. Even if the bids are placed as an aggregated bid, the question arises if the baseline needs to be for every load participating to be able to both verify the loads activated and to provide correct settlement for costs and rewards.

France and Belgium (for specific products) are the only MS that has opened wholesale and balancing markets to independent aggregators. The relationship between aggregators and retailers/BRPs is regulated, and a standardized process has been put in place. In France even residential consumers have been activated, possibly due to aggregation-friendly product definitions. However, there are ongoing disputes about the imbalance settlements and the level of compensation (JRC, 2016).

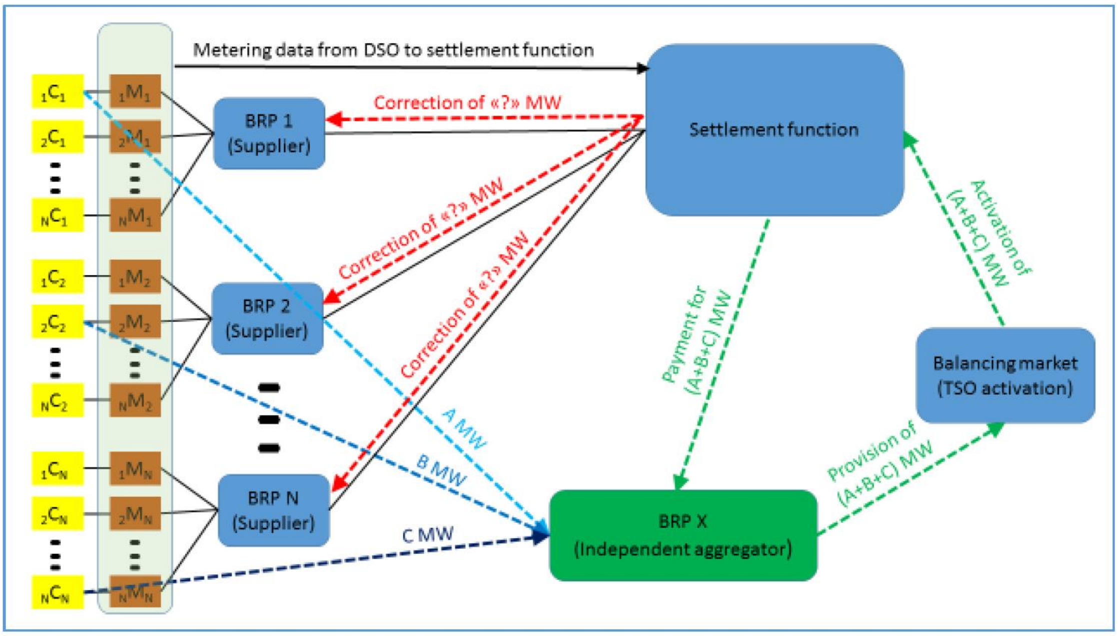
In Germany, aggregators must currently make bilateral agreements with the balance responsible supplier on compensation, and there is no standard agreement or no obligation for the retailer to enter into such agreements (JRC, 2016).

Aggregators as BRPs

An alternative way of dealing with balancing responsibilities is to make both suppliers and aggregators BRPs, and let the TSOs handle the imbalance settlement between the different BRPs. Acer states in their recommendation for NC balancing codes in 2015 that aggregators should be able to operate without consent or contract with the supplier (BRP), and that the aggregator in that case should be BRP in addition to the BRP for the same connection point. The TSO should then adjust positions and determine the final positions for both BRPs; the supplier and the aggregator. The TSO will also be responsible for the financial settlement for both parties. In this case the aggregator will have a profit in the markets as long as the reward for activation is higher than the reimbursement to the supplier which will normally be the case.

In this case, two BRPs are responsible for the same consumer/connecting point. If a high number of consumers end up having two BRPs, however, the settlement process may become extremely complex and costly. The baseline for supplier's bids or nomination is set for the total load from all the suppliers customers and the aggregators bids also represents an aggregated volume for a number of loads. The activated loads will correspond to consumers from many different suppliers. According to NordREG (2016), it seems challenging to ensure a correct estimate of the different BRP's imbalances, as the settlement function would not be able to separate the origin of the aggregated imbalance volumes. A mitigating measure may be to require the independent aggregator to split and separate the demand response bids according to from which supplier's BRP the demand response originates. Even if this separation is made, it seems challenging for the settlement function to validate if the bids are correctly split between the different supplier's BRPs. Address (2011) argues that if this option gives widely used DR from independent aggregators, there is no longer any way of setting up a reference baseline for the consumers involved in aggregated bids. Unless there is a baseline and a separate settlement calculation for every load involved in the bids it will be impossible to know which deviations for the baseline is a result for actual imbalances or activation of DR.

Figure 5-17: The balancing settlement for two BRP on the same connection point



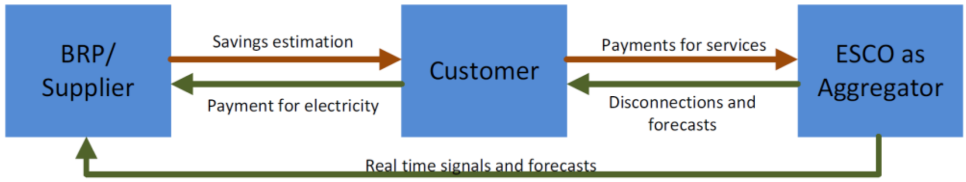
Source: NordREG (2016)

Aggregators operate independently of balancing costs

One could argue that independent aggregators could be an option to increase DR from small consumers as the administrative procedures for the different models of settle imbalances and costs are administratively heavy. However, this is not in line with the pro-activeness of DR in the target model as it will make scheduling for the operating hour less accurate, the same resource may be double rewarded and the risk for the supplier will increase.

Aggregators that are not BRPs will not have to face imbalance costs due to demand response. As the aggregator faces no risk of penalties in the markets, this option will increase the risk of gaming by aggregators (Address, 2011).

Figure 5-18 Independent aggregator without balancing cost, information of actions to the retailer



Source: Enfo Energy AS and The Norwegian Smart Grid Centre (2014)[112]

NordREG (2016) presents some examples of cases where an aggregator without balance responsibility place bids in the market for system services, of which we present one example in the textbox below. As we can see, since the "independent aggregator" does not have balance responsibility, it would, in this setup, end up with a positive net result of 550 €, i.e. the full value of the upward regulating bid. At the same time, the supplier is also rewarded for the same demand response, as it has an imbalance that is helping the market. Due to the two-price system in the Nordic imbalance settlement, the supplier – who is a passive contributor as it does not participate actively in the balancing market – is compensated based on the day-ahead price, while the aggregator – who has actively bid the DR into the balancing market – is paid according to the marginal balancing price, which, in the Nordic market, has to be higher than the day-ahead price.

The double rewarding of the demand response implies a net increase in the total cost settlement. These losses would somehow need to be covered, either by the grid users through tariffs or by other BRPs in the balance settlement. According to the suggested NC of balancing from ACER, the terms and conditions for imbalance prices will be set up by the TSOs, and the suggested pricing will generally have the same risk of double awarding for independent aggregators as the Nordic model.

Scenario:

1. The BRP (supplier) has procured 10 MWh in the DA market
   ➔ The supplier submits a consumption schedule of 10 MWh
2. The Independent Aggregator is not a BRP and has no supply commitment, and therefore does not procure electricity in the DA market
   ➔ The aggregator does not submit a schedule
3. The Independent Aggregator (not BRP) submits a 10 MWh upward regulating bid to the balancing market
4. The TSO buys a 10 MWh upward regulating bid from the Independent Aggregator (not BRP)

Financial result of the BRP (supplier):
Since the BRP (supplier) has a consumption schedule of 10 MWh, but ends up consuming 0 MWh, the BRP (supplier) would have a positive imbalance of 10 MWh. Further, the BRP (supplier) has already procured 10 MWh in the DA market. The net result of this in would be:

Market	Volume	Price	Cost/payment
Procurement in DA	-10 MWh	50 €/MWh	-500 €
Sale of balancing bid	0 MWh	55 €/MWh	0 €
Settlement position	10 MWh	55 €/MWh	550 €
Net result			**50 €**

The BRP (supplier) would end up with a net result of 50 €, since it would end up with a positive imbalance of 10 MWh. (Note that the positive net result is due to the Nordic market rules which imply that the retailer is compensated for imbalances that helps the system according to the reserve price.)

Financial result of the Independent Aggregator (not BRP):

Since the Independent Aggregator (not BRP) does not have balance responsibility, it would not have an imbalance or even be settled for imbalances. It would only receive a payment from the TSO for the 10 MWh upward regulating bid. This net result of this would be:

Market	Volume	Price	Cost/payment
Procurement in DA	0 MWh	50 €/MWh	0 €
Sale of balancing bid	10 MWh	55 €/MWh	550 €
Settlement position	0 MWh	55 €/MWh	0 €
Net result			**550 €**

Source: Nord Reg (2016)

To reduce the retailers' balancing costs caused by aggregators, the aggregator or the consumer could be required to inform the supplier about the agreed terms of load changes between the consumer and the aggregator. In such arrangements, the BRP may include the costs or the risk of imbalances in the contractual terms with the consumer. However, the savings of the consumer by providing demand response via an aggregator may be significantly reduced by increased costs to the supplier. On the other hand, if the actions of the aggregator can be foreseen by the retailer, there is also a chance that aggregators predicable actions are taken into account when the supplier places bids (if there is no baseline per activated load).

Conclusion on the aggregators role within the EU target model

There are two main questions regarding aggregators in the wholesale energy markets:

- Should aggregated bids be allowed?
- If so, how should the aggregated loads be verified and settled to ensure fairness for all parties involved?

Aggregation is probably the only way of activating loads for consumers not being BRP themselves. One should note, however, that suppliers aggregate loads of their consumers when they bid into the energy markets and knowledge of price sensitivity in the retail market will then convert into price-sensitive bids in the DA market. A large part of the DR potential comes from smaller loads that may in total make a difference in managing the power system. To overcome the barrier of minimum volumes in balancing and capacity markets, small commercial loads may be aggregated and bid into the markets in one “block”. An aggregator could exploit economies of scale by aggregating DR from several suppliers, thereby being able to place more competitive bids. Small loads (commercial and buildings) must be handled in a simple and standardized way to reduce costs – if not, they will not be cost efficient flexibility sources compared to larger loads (industry) or generation. Aggregators may play an important role to bring some economy of scale in DR from smaller loads.

Aggregators will also simplify the use of DR for the TSOs. The higher the number of bids in the markets, the more complicated the operation and activation of bids. Aggregators help limit the increase in bids and at the same time bring new loads into the market places.

We have discussed four different ways to organise aggregation. The table below shows how each option affects the need for a baseline per load, what settlement process is needed and how risk is divided between the supplier and the aggregator. The first and the last option has the lowest administration and complexity in the settlement process. The first option, suppliers offers aggregated DR, is the simplest set-up in all terms, as this can be done without changing any main processes in the EU target model. The two models with a financial settlement between suppliers and aggregators introduce complexity in the settlement, since compensation between the parties must be handled, but shares the risk between the two parties. This requires a discussion on what the compensation for energy should be, a question there is no exact answer to. The first option does not introduce any new risk for the retailer as they have full control of their own actions, bids and responsibilities. If there is no settlement between the retailer and the aggregator, the supplier will hold the full risk imbalances (which may in some cases also be to their benefit), but will generally increase the cost for the system (by double-rewards) compared to the other options representing a zero-sum game. The supplier will in this case have a responsibility (being BRP), but do not have the power to handle this risk – or to take on the full responsibility of being BRP.

Table 16: Summary of different organisation of the aggregator role

Option	**Baseline**	**Settlement**	**Risk**
Aggregated DR as part of suppliers service	No (suppliers bid is sufficient)	Not needed	No added risk
Bilateral settlement (standard)	Per load	Per load, suppliers and aggregator	Shared, but depending on the agreement
Supplier and aggregator BRP for the same load	Per load	Per load, suppliers and aggregator	Shared
No settlement between aggregator and supplier	Per load	Per load – energy Per aggregator - financially	Supplier and the system takes the risk, and incentives for gaming (aggregator)

Allowing aggregators, or rather, small loads to participate in the market could be a means to enhance the competition, both towards large industries delivering most DR today, and also to the generation companies. Increased competition could reduce overall system costs as long as a level playing field is ensured for all participants. In that sense, aggregators should not have any advances compared to other market participants in the long run, even if one could give incentives in the short run to increase aggregators' role in the markets in order to enhance demand response. First, the barriers for market entry should be lowered including any unnecessary barriers for becoming a BRP in the market.

In addition, or to speed up this process, independent aggregators may be allowed to challenge the usual business of traditional suppliers. Setting up regulated standard agreements for the regulation of the relationship between the BRP and the aggregator could reduce the barrier to entry for aggregators. Up to a certain volume, or for a limited time, aggregators may also be allowed to operate independently of balancing responsibility to help establishing a market for aggregated DR until a better solution is established. This is mostly relevant for MS where demand side do not have access to day-ahead markets.

In the longer term however, the role of the aggregator should be integrated with the role of the supplier or the aggregator should be held responsible for the cost of the imbalances they cause, in order to ensure a level playing field for all market participant and to not allow independent aggregators to be free riders. An alternative is to partly or fully release the suppliers from the balancing responsibility and let the TSO take over the scheduling responsibility. Other implications of this must then be taken into account. The suppliers will no longer have the incentive to promote proactive DR from their consumers and the nomination will be administrative rather than market based.

5.4.4 Measures to increase incentive-based DR

Important policies to facilitate and incentivize DR in all markets is to ensure that all market players, on both the generation and the demand side, can participate on equal terms. At the same time, to ensure efficient market solutions, it is also important that all participation is associated with a balance responsible party. The balance responsibility ensures that a large part of the planning of the system balance up to real-time is entrusted to the market participants in the day-ahead and intraday markets, while the momentary balance is the responsibility of the authorities, i.e., the TSOs by delegation.

Important barriers to incentive-based DR identified by SEDC, cf. section 3.2.3, are that

- Loads are not accepted as a resource in the markets (neither directly nor by aggregation)
- Programme requirements block demand-side participation
- There are no measurement and verification rules for DR participation (neither directly nor by aggregation)
- The payment structure is inadequate and non-transparent, and penalty structures act as a critical barrier

Policies to increase or introduce DR in the market should thus be directed at these barriers. Possible measures to incentivise participation of DR in wholesale markets, besides allowing such participation, include:

- To ensure that demand participates at a level playing field with generation
- To reduce the market resolution (i.e. from hourly to 15 minutes or less)
- To move market closure closer to the operation hour
- To extend the number of bidding possibilities to take account of the wider range of heterogeneity on the demand-side
- Allowing aggregated bids when possible

Correspondingly, possible concrete measures to incentivise DR participation in balancing markets are:

- Reduce minimum bid volumes to allow for smaller loads to participate

- Adjust product designs to better fit the demand side (bid size, duration, recovery time, response time, etc.)

- Set up standard processes and settlement between aggregators and suppliers

It should be noted that these measures are not independent of each other. If the market resolution is not adapted to the participation of demand-side resources in terms of product definitions and market resolution, ensuring a level playing field with generation may not accomplish much.

5.4.5 Approach to estimation of DR potential in the options

So how much of the (remaining) DR potential could changes in regulations and market designs, plus implementation of incentive-based schemes bring about?

In general, there is no limit to how much of the (remaining) theoretical DR potential that incentive-based mechanisms could deliver, if barriers are removed and incentives are made strong enough. Hence, the expected potential for incentive-based DR depends on:

› The removal of barriers to DR
› The remuneration of DR in different schemes

The first step is to remove the barriers to DR. The policy options presented in chapter 4 focus on a step-wise removal of the main barriers related to DR participation in the markets:

› Consumer access and aggregation
› Programme description and requirements
› Finance and penalties

The first step is of course to allow DR participation in the markets, and to provide the rules and regulations to ensure a level playing field. However, as argued above, and as shown by some of the experience, adaptation of product definitions and the facilitation of aggregation should also reduce the barriers for participation.

Secondly, the potential depends on the cost of providing the flexibility, the price structures and the alternative flexibility resources in the market. It is likely that the potential will grow over time as technology is developed and more widely used, as well as due to innovation in contractual arrangements and service definitions.

It should be apparent from the above sections that the basis for estimating the potential for DR based on different policy measures is very weak indeed. We have some evidence and estimates from different countries, but many schemes are limited and for many schemes it is still early days. Some reasons why it is difficult to draw solid conclusions based on the evidence are:

- The experience from one market cannot easily be transferred to another as the potential for incentive-based DR depends on the general market design, including the degree of price-based DR. For example, the US in general has a market design that is very different from the European target model.

- The price structure and the exposure of end-users to TOU or RTP pricing, and hence the resulting price-based DR, varies between markets. For example, the Nordic market is characterized by much smaller diurnal price variations than markets in the rest of Europe, while in many MS retail prices are to a large extent regulated, heavily influenced by taxes and levies, or based on averages.

- The potentials realized in small pilot experiments may be over-estimated for several reasons: self-selection of participants, combination with information and novelty motivation, short time duration, non-cost based compensation, etc.

The specific assumptions for each of the options is presented further in subsequent section on each option. Before assessing the business as usual case, the next sub-section discusses possible overlaps between the estimation of price and incentive based demand response.

5.4.6 Link between price and incentive based demand response

There is an obvious link between price based DR and the demand sides' participation in the wholesale energy market for suppliers representing small consumers. The supplier (BRP) place purchase bids (or nominations) on behalf of their customers. The bids may be price-sensitive based on the experience of the supplier when it comes to how its customers adjust to prices. Hence, the bids may reflect to some extent price-based DR of end-users, depending on their exposure to wholesale market prices. In addition, or alternatively, the supplier may employ incentive-based schemes with explicit contracts with its customers, on which basis it can place more flexible bids in the day-ahead market. Such incentive schemes may be promoted via provision of home automation, information in the case of peak-prices in the day-ahead market, etc.

On the one hand, Price-based Demand Response can be accessed by a wider range of consumers through supplier-enabled dynamic pricing programmes. To some extent price-based DR can be thought of as "easy DR" (low-hanging fruits). However, the potential for incentive-based DR is probably larger if the price-based potential is not already tapped into. For example, if end-users only face average retail prices, they have a weak incentive for price-based DR, and the potential that can be activated by incentive-based mechanisms is larger.

On the other hand, activation of price-based DR by way of smart metering and RTP pricing, may make it easier for end-users to participate in incentive-based schemes as well. (By the same line of argument, incentive-based schemes involving installation of smart meters may increase price-based DR, as it gives end-users the means to respond to hourly prices – and to choose TOU or RTP pricing if available.)

Regarding the link between price and incentive based demand response; the following is our approach:

- Industrial customers that act as BRP are unlikely to respond directly to price, but will bid in volumes of consumption into day ahead and intra-day markets and may also participate in balancing and capacity markets. Hence, the key mechanism will be incentive-based DR.

- Smaller residential customers may respond to price signals. Aggregating their load to participate in wholesale balancing and capacity markets is administratively complex under the Target Model (due to the need for a baseline and settlement of energy and financial compensation per activated load), and potentially costly. Hence, the key mechanism will probably be price-based DR. Smaller commercial customers can be considered similar to residential customers in this respect.

- For the medium to larger commercial customers both mechanisms could apply:

    - Once these customers have smart meters and automation they could respond to prices as long as they know the day-ahead price etc., (price-based)
    - In addition, they could cooperate with suppliers, or aggregate balancing reserve in the balancing and capacity markets (incentive-based).

- Relating the above to the levels of incentive based DR:

    - For all MS (except Finland where industrial loads are relatively high) with incentive based DR volumes in todays situation, the actual level is higher than the industrial Gils potential. This means that either Gils potentials are low or non-industrial loads are providing DR.
    - To avoid double counting, we have not included any (extra) volumes in the policy options for the energy market in addition to volumes found in balancing and capacity markets.
    - In policy option BAU – all MS (except the MS already reporting DR levels) have incentive based DR lower than industrial potential
    - In policy option 1 – MS have lower or slightly over the industrial Gils potential (with the same exception as above)
    - In policy option 2 and 3, most MS have higher incentive based DR than the industrial potential, meaning that commercial loads must participate. This is also in line with the fact in bullet point one

Where the market is more price sensitive for small customers will it affect the incentive-based response of larger customers?

- For this to be the case, price-based DR of small customers would need to reduce price volatility in wholesale markets. As small customers will not participate directly in these markets, the impact on price formation is not clear cut. The impact of price based DR on incentive based DR may depend on how the retailer responds in the wholesale market by experiencing price response in the consumer markeds and turn this in to price-dependent bids in the DA and ID markets.

- Where there is more equipment and automation to drive price-based DR, this equipment will also be available to promote incentive-based DR, as long as the equipment allows for remote control from i.e., an aggregator.

Can the price-based and incentive-based responses be added?

- It will not always be the case that the price-based and incentive-based responses work at the same period. While some price-based response will respond to price (particularly where automation is involved), other response may be more closely linked to reducing peak loads (more sophisticated ToU tariffs, CPPs), whereas incentive-based measures will affect periods of high prices that need not necessarily correspond to peak load, but rather low generation or incidents affecting security of supply or imbalances.

- Commercial customers could decide whether to be compensated through price or be dispatched – therefore participation is a case of either through price based approaches or incentive based mechanisms – i.e., we have to be careful not to double count.

- Commercial customers could also choose to be first lower their loads based on price signals, and then bid in the rest of the load to balancing or capacity markets. In this case, the potential for incentive based DR is lowered by the price response, but a portion is still there.

5.5 Business as usual

Based on the assessment of price and incentive based demand response, the specific estimation of how much demand response will be realised under the BAU option is described in the following two sub-sections.

5.5.1 Assessment of price-based DR in BAU

Based on the stated methodology as described in Section 5.3, the resulting estimates of incremental price based DR estimates in the BAU scenario are set out below. These figures are over and above the estimates of more “traditional” price based DR set out in section 5.3.1. These assume that across the EU-28 the following load is shifted or reduced:

- 2016 – 5,779 MW (99.6% standard appliances, 0.4% EV,HP, SA)

- 2020 – 6,433 MW (88% standard appliances, 12% EV,HP, SA)
- 2030 – 15,383 MW (35% standard appliances, 65% EV,HP, SA).

The estimate by country is set out in the following table.

Table 17: Price based DR – BAU scenario 2016, 2020, 2030 (MW)

Member State	**2016**	**2020**	**2030**
Austria	94	104	326
Belgium	130	116	75
Bulgaria	54	46	29
Croatia	34	30	20
Cyprus	12	11	8
Czech Republic	93	80	50
Denmark	78	97	251
Estonia	15	16	33
Finland	140	156	375
France	841	963	2915
Germany	930	842	1441
Greece	137	145	241
Hungary	88	76	48
Ireland	49	69	206
Italy	699	848	2559
Latvia	19	20	37
Lithuania	27	23	15
Netherlands	195	226	661
Poland	306	318	646
Portugal	90	79	56
Romania	128	131	240
Slovakia	60	55	56
Slovenia	22	19	11
Spain	537	689	1815
Sweden	269	299	633
UK	733	976	2634
TOTAL	5779	6433	15383

Source: Own calculations

5.5.2 Incentive based demand response

The baseline option assumes that the current incentive-based DR mechanisms are continued, and that new efforts are meagre. As we have shown in section 3.2.3, the existence of incentive-based mechanisms varies between Member States. Moreover, existing schemes differ, and only a few MSs employ several schemes. Hence, the modelling of the baseline should be based on an MS-to-MS assessment.

Looking at the different consumer groups (processing industry, C/I, retail), we may assume that where access to the market is allowed, some large industry (as BRP) is in a position to participate directly in the markets, i.e. both in the wholesale and in the balancing/reserve markets. When it comes to C/I customers, they are likely to only participate via aggregators, provided that they have smart metering, etc. We do not expect retail customers to be able to participate in incentive-based DR.

These are very different flexibility products: Energy efficiency (EE) may participate in capacity mechanisms, if EE investments permanently lower demand levels, including peak demand. Demand interruption is easy to measure, while demand reduction of time-shift of demand may be related to a baseline.

The possibility of participation by DR does not imply that the full potential can be activated if prices are high enough. For example, there may be no discrimination between generation and demand in the regulation or product definitions in the reserve markets. Still, the volumes, response time, duration and other characteristics, defined by the TSO, may serve as a barrier for participation in DR in these markets.

In general, it can be assumed that incentive-based DR is non-existing or limited in some MS in the baseline scenario, i.e. MS not having introduced the EU target model. However, some MS have reported high levels of DR in line or even above levels in US markets. In the estimate of DR levels, the price sensitivity in the energy wholesale market is not included in the table, but levels up 18 % of peak load have been seen in some MS.

It is assumed that further uptake of the incentive based demand response will require further changes to the regulation; see the assumptions for Option 2.

The estimation approach for incentive based DR

- DR potential is based on evidence where available –in terms of % of peak load. For countries where no evidence is available, the following estimates were applied:
  - For MS where DS is not allowed in markets: 0 % of peak load
  - For MS where DS is allowed to participate in the energy wholesale market: 0.5 % of peak load
  - For MS where DS is allowed in energy markets and two additional markets: 1.0 % of peak load

These levels are low compared to the levels we have found in MS where the DS is allowed to participate. Below is an example of how these rules are applied to the BAU, including actual volumes of DR where this is found. The assumptions for the BAU by Member States are presented below.

Table 18: Assumptions for Incentive based DR – BAU scenario 2016, 2020, 2030

Country	Peak load in GW			BAU assumptions for peak load reductions		
	2016	2020	2030	2016	2020	2030
Austria	10	11	12	1.00%	1.00%	1.00%
Belgium	14	14	15	5.00%	5.00%	5.00%
Bulgaria	6	6	6	0.00%	0.00%	0.00%
Croatia	3	3	4	0.00%	0.00%	0.00%
Cyprus	1	1	1	0.00%	0.00%	0.00%
Czech Republic	10	10	12	0.50%	0.50%	0.50%
Denmark	6	6	7	10.00%	10.00%	10.00%
Estonia	1	1	2	0.00%	0.00%	0.00%
Finland	14	14	14	6.00%	6.00%	6.00%
France	84	87	85	2.00%	2.00%	2.00%
Germany	86	84	98	1.00%	1.00%	1.00%
Greece	8	9	12	19.00%	19.00%	19.00%

Country	Peak load in GW			BAU assumptions for peak load reductions		
	2016	2020	2030	2016	2020	2030
Hungary	6	6	7	0.50%	0.50%	0.50%
Ireland	5	5	5	1.00%	1.00%	1.00%
Italy	52	55	64	8.00%	8.00%	8.00%
Latvia	1	2	2	0.50%	0.50%	0.50%
Lithuania	2	2	2	0.00%	0.00%	0.00%
Netherlands	17	17	20	1.00%	1.00%	1.00%
Poland	23	24	30	1.00%	1.00%	1.00%
Portugal	8	8	10	0.50%	0.50%	0.50%
Romania	8	8	12	1.00%	1.00%	1.00%
Slovakia	4	4	5	1.00%	1.00%	1.00%
Slovenia	2	2	3	1.00%	1.00%	1.00%
Spain	42	46	58	5.00%	5.00%	5.00%
Sweden	22	23	25	3.00%	3.00%	3.00%
United Kingdom	51	50	55	3.50%	3.50%	3.50%
Total	486	500	568			

Source: Own calculations and peak load data from Entso-E

The percentages are converted to % of theoretical potential to enable estimates of DR on end use level. The results are presented in the below table.

Table 19: Incentive based DR – BAU scenario 2016, 2020, 2030 (MW)

Member State	2016	2020	2030
Austria	104	106	122
Belgium	689	697	749
Bulgaria	0	0	0
Croatia	0	0	0
Cyprus	0	0	0
Czech Republic	49	49	61
Denmark	566	592	716
Estonia	0	0	0
Finland	810	846	836
France	1689	1744	1695
Germany	860	840	984
Greece	1527	1640	2305
Hungary	30	31	37
Ireland	48	49	50
Italy	4131	4367	5109
Latvia	7	8	10
Lithuania	0	0	0
Netherlands	170	171	200
Poland	228	244	300
Portugal	40	42	50
Romania	79	82	123

Member State	2016	2020	2030
Slovakia	40	43	48
Slovenia	21	23	26
Spain	2083	2288	2898
Sweden	666	685	748
United Kingdom	1792	1764	1922
Grand Total	15628	16309	18988

Source: Own calculations

5.6 Policy option 1

Similar to the assessment of BAU, the potential for price and incentive based demand response under policy option 1 is assessed and estimated using the approach and methodology described in Section 5.3 and 5.4.

5.6.1 Price based demand response

The main difference between this option and the BAU is that price-based demand response would be greater in scope due to the broader take up of smart meters by customers. Moreover, where customers are choosing to take up a smart meter it is anticipated that this will be accompanied by some form of STOU, RTP or CPP pricing.

The resulting estimates of price based DR under Option 1 are set out below. These assume that across the EU-28 the following load is shifted or reduced:

- 2016 – 5,779 MW (99.6% standard appliances, 0.4% EV,HP, SA)
- 2020 – 6,943 MW (86% standard appliances, 14% EV,HP, SA)
- 2030 – 17,862 MW (33% standard appliances, 67% EV,HP, SA).

The estimate by country – as well as the increment over BAU in 2030 is set out in the following table.

Table 20: Price based DR – Option 1 scenario 2016, 2020, 2030 (MW)

Member State	2016	2020	2030	Increase 2030 compared with BAU
Austria	94	123	339	13
Belgium	130	122	366	291
Bulgaria	54	47	94	65
Croatia	34	30	58	38
Cyprus	12	11	20	12
Czech Republic	93	83	175	125
Denmark	78	97	260	9
Estonia	15	17	34	1
Finland	140	156	388	13
France	841	1135	3022	107
Germany	930	986	2552	1111
Greece	137	147	247	6
Hungary	88	77	137	89

Member State	2016	2020	2030	Increase 2030 compared with BAU
Ireland	49	69	214	7
Italy	699	956	2648	89
Latvia	19	21	38	1
Lithuania	27	23	40	25
Netherlands	195	254	684	23
Poland	306	324	662	16
Portugal	90	83	246	190
Romania	128	133	246	5
Slovakia	60	62	98	42
Slovenia	22	19	40	28
Spain	537	689	1874	59
Sweden	269	299	653	20
UK	733	976	2727	94
TOTAL	5779	6943	17862	2479

Source: Own calculations

The results show at an EU-26 (not enough data available for Malta and Luxemburg) level an additional 2.5 GW of demand response than under the BAU scenario. Greatest benefits are shown in Germany, Belgium and Portugal, reflecting the assumption that a large number of customers will choose to take up a smart meter, and in these cases a form of dynamic tariff. While high, the resulting estimates of customers with dynamic tariffs in Germany, Belgium and Portugal in 2030 is similar to the estimate of electric vehicles assumed to be in place by this date. The lowest increases are found in MS that already are assumed to have policies that promote price based demand response (UK, Ireland, Denmark, Finland, Spain and Sweden).

On the whole, the results show that in 2030 at an EU-wide level:

- For normal appliances, 4.9% of potential demand response is captured, while
- For electric vehicles, heat pumps and smart appliances, 18.6% of potential demand response is captured.

These estimates are sensitive to the take up of new forms of tariff and in particular RTP/CPP. The proportion of potential DR for electric vehicles and heat pumps captured ranges from around 13% for MS not currently supporting a widespread roll out of smart metering systems to around 21% if it is planning a full scale roll-out.

5.6.2 Incentive based demand response

Option 1 does not include anything that will fundamentally change the situation for incentive based demand response, and therefore the level is similar to the level assumed under the BAU.

Table 21: Incentive based DR – Option scenario 1, 2016, 2020, 2030 (MW)

Member State	2016	2020	2030
Austria	104	106	122
Belgium	689	697	749

Member State	2016	2020	2030
Bulgaria	0	0	0
Croatia	0	0	0
Cyprus	0	0	0
Czech Republic	49	49	61
Denmark	566	592	716
Estonia	0	0	0
Finland	810	846	836
France	1689	1744	1695
Germany	860	840	984
Greece	1527	1640	2305
Hungary	30	31	37
Ireland	48	49	50
Italy	4131	4367	5109
Latvia	7	8	10
Lithuania	0	0	0
Netherlands	170	171	200
Poland	228	244	300
Portugal	40	42	50
Romania	79	82	123
Slovakia	40	43	48
Slovenia	21	23	26
Spain	2083	2288	2898
Sweden	666	685	748
United Kingdom	1792	1764	1922
Grand Total	15628	16309	18988

Source: Own calculations

5.7 Policy option 2

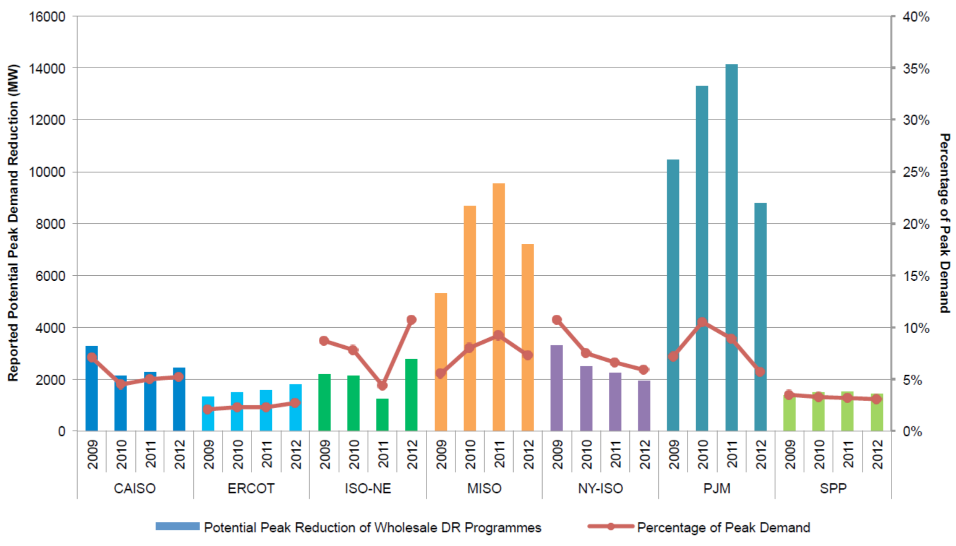
This section presents how the potential for price and incentive based demand response under policy option 2 is assessed and estimated using the approach and methodology described in Section 5.3 and 5.4.

The potential for price based demand response is assumed to be the same as under policy Option 1.

5.7.1 Incentive based demand response

There is international evidence that the demand side may provide peak load reductions of 1-2 per cent of peak load from participation in the wholesale market and 1-6 per cent of peak load from other incentive based DR (Brattle, 2015). Data from FERC summarised by Brattle (2015) and University of Oxford (2015) indicates a total incentive based DR of approx. 8 per cent of peak load reductions in PJM where the incentive based DR has the largest uptake. Some US markets have even had more than 10 per cent peak reductions from DR one of the years between 2009 and 2012, see figure below.

Figure 5-19: Levels of incentive based DR in terms of MW and peak load reductions



Source: University of Oxford (2015)

DR is already represented in some way in the wholesale energy markets in half of the member states. In policy option 2, we assume that all member states having introduced some incentive based DR already will reach a level of 5 per cent peak reduction in 2030, gradually increasing from today's level. The increased level of DR compared to option 1 is due to adjustments in programme requirements to better reflect the needs of demand side. This includes allowing aggregated bids in the markets allowing to aggregators enter the market as a service provider for the industry and large commercials. There is also a standard process for settlements between aggregators and suppliers to facilitate aggregation.

Also, all member states will introduce incentive based DR and the MS not currently having incentive based DR, will reach a level of 3 per cent of peak load in 2030, the potential gradually being introduced from 2021. The reasoning for take-up of DR in these MS are the same, but they will start from a lower level than MS where DR is already taking place.

The estimation approach for incentive based DR comprises the following steps:

- DR potential is based on evidence where available – often in terms of % of peak load. For countries where no evidence is available, the following estimates were applied:
  - For MS where DS is not currently allowed in any markets: 3 % of peak load in 2030, gradually increasing from 0 % in 2016
  - For MS where DS is already allowed to participate in the energy wholesale market: 5 % of peak load, gradually increasing from 0.5% in 2016
  - For MS where DS is allowed in energy markets and two additional markets: 5 % of peak load, gradually increasing from 1% in 2016

- These levels are low compared to the levels we have found in MS where the DS is allowed to participate. Below is an example of how these rules are applied to the BAU.

The percentages are converted to % of theoretical potential to enable estimates of DR on end use level using data as described under the BAU. The results are illustrated in the below table.

Table 22: Incentive based DR – Option scenario 2, 2016, 2020, 2030 (MW)

Member State	2016 (MW)	2020 (MW)	2030 (MW)
Austria	104	227	612
Belgium	689	697	749
Bulgaria	0	55	167
Croatia	0	29	123
Cyprus	0	8	42
Czech Republic	49	174	612
Denmark	566	592	716
Estonia	0	19	95
Finland	810	846	836
France	1689	2740	5085
Germany	860	2040	5901
Greece	1527	1640	2305
Hungary	30	130	441
Ireland	48	118	300
Italy	4131	4367	5109
Latvia	7	19	59
Lithuania	0	15	68
Netherlands	170	366	1001
Poland	228	522	1499
Portugal	40	149	496
Romania	79	175	615
Slovakia	40	68	144
Slovenia	21	49	132
Spain	2083	2419	3477
Sweden	666	815	1247
United Kingdom	1792	1980	2745
Grand Total	15628	20260	34575

Source: Own calculations

5.8 Policy option 3

This section presents how the potential for price and incentive based demand response under policy option 3 is assessed and estimated using the approach and methodology described in Section 5.3 and 5.4.

The potential for price based demand response is assumed to be the same as under policy Option 1.

5.8.1 Incentive based demand response

In policy option 3, we assume that all member states having introduced some incentive based DR already will reach a level of 8 per cent peak reduction in 2030, gradually increasing from today's level. In addition, all member states will introduce incentive based DR and the MS not currently having incentive based DR, will reach a level of 5 per cent of peak load in 2030, the potential gradually being introduced from 2021.

The increased level of DR compared to option 2 is due to aggregators entering the market as a service provider for the commercial sector. In addition, the prices for balancing reserves have increased due to increased imbalances in the energy market.

The estimation approach for incentive based DR comprises the following steps:

- DR potential is based on evidence where available – often in terms of % of peak load. For countries where no evidence is available, the following estimates were applied:
    - For MS where DS is not currently allowed in any markets: 5 % of peak load in 2030, gradually increasing from 0 % in 2016
    - For MS where DS is already allowed to participate in the energy wholesale market: 6.5 % of peak load, gradually increasing from 0.5% in 2016
    - For MS where DS is allowed in energy markets and two additional markets: 6.5 % of peak load, gradually increasing from 1% in 2016
- These levels are low compared to the levels we have found in MS where the DS is allowed to participate. Below is an example of how these rules are applied to the BAU.

The percentages are converted to % of theoretical potential to enable estimates of DR on end use level using data as described under the BAU. The results are illustrated in the below table.

Table 23: Incentive based DR – Option scenario 3, 2016, 2020, 2030 (MW)

Member State	2016 (MW)	2020 (MW)	2030 (MW)
Austria	104	272	796
Belgium	689	757	974
Bulgaria	0	91	279
Croatia	0	48	205
Cyprus	0	13	70
Czech Republic	49	216	795
Denmark	566	592	716
Estonia	0	25	123
Finland	810	866	905

Member State	2016 (MW)	2020 (MW)	2030 (MW)
France	1689	2865	5509
Germany	860	2160	6393
Greece	1527	1640	2305
Hungary	30	139	478
Ireland	48	125	325
Italy	4131	4367	5109
Latvia	7	28	99
Lithuania	0	25	113
Netherlands	170	439	1301
Poland	228	627	1949
Portugal	40	185	645
Romania	79	210	800
Slovakia	40	93	240
Slovenia	21	58	172
Spain	2083	2484	3767
Sweden	666	913	1622
United Kingdom	1792	2196	3569
Grand Total	15628	21435	39255

Source: Own calculations

5.9 Summary of effects

The total demand response under each of the policy options is summarised in the table adding the price and incentive based demand response.

Table 24: Total DR potential price + incentive based in 2030 (MW)

Member State	BAU	PO1	PO2	PO3
Austria	450	460	950	1130
Belgium	820	1110	1110	1340
Bulgaria	30	90	260	370
Croatia	20	60	180	260
Cyprus	10	20	60	90
Czech Republic	110	240	790	970
Denmark	970	980	980	980
Estonia	30	30	130	160
Finland	1210	1220	1220	1290
France	4610	4720	8110	8530
Germany	2420	3540	8450	8940
Greece	2550	2550	2550	2550
Hungary	90	170	580	620
Ireland	260	260	510	540
Italy	7670	7760	7760	7760
Latvia	50	50	100	140
Lithuania	10	40	110	150

Member State	BAU	PO1	PO2	PO3
Netherlands	860	880	1680	1980
Poland	950	960	2160	2610
Portugal	110	300	740	890
Romania	360	370	860	1050
Slovakia	100	150	240	340
Slovenia	40	70	170	210
Spain	4710	4770	5350	5640
Sweden	1380	1400	1900	2270
United Kingdom	4560	4650	5470	6300
Total	34380	36850	52420	57110

5.10 Cost and benefits of options

Based on the assessment of the demand response under the alternative policy options, the net effects on the overall electricity system costs are estimated.

The effects include the change in costs and the change in benefits. Wider, indirect economic impacts are not included in the assessment. Wholesale market prices that are associated with the different scenarios have not been explicitly modelled. In a well-functioning market however reduction of costs will mean a reduction in prices.

5.10.1 Costs of options

To make demand response and its benefits possible, cost need to be incurred in the system. For the activation costs of demand response three classes are defined:

Parameter	Cost component	Unit
Variable costs	Costs for loss of production, inconvenience costs, storage losses	€/kWh
Annual fixed costs	Information costs, transaction costs, control costs	€/kW
Investment costs	Installation of measurement-equipment, automatic measurement for control, communication equipment	€/kW

Variable costs for demand response are the costs for using the potential demand response. In case of load shifting these costs are assumed to be zero since in many cases the lost output can be produced later.[113] When loads are curtailed, variable costs are not zero however, load curtailment is not analysed in this study. Moreover, it is possible that demand response causes additional costs for inconvenience or efficiency losses due to partial load operations, however these costs are not considered in this study.

The annual fixed costs are incurred on a regular basis and are not related to the actual use of demand response. Predominantly, these costs relate to administration and to incentivise consumers for demand response. This study only focusses on the system costs, therefore the annual fixed costs are assumed zero.

Investment costs are incurred once the demand response potential is activated. Costs of this type include

- Investments in **communication** equipment both at the consumer side as in the grid. This enables remote sending of instructions to the consumers which then can provide demand response.
- Investments in **control** equipment are needed to carry out load reductions automatically. With control equipment it is possible to provide demand response upon receipt of a signal.
- **Metering** equipment is required to be able to verify that the load reduction is achieved.

At the moment there is relatively little information available of these investment costs for demand response. Per consumer type, the method to determine the costs is explained.

Industrial consumers often already have equipment installed that can activate demand response. On average, it is however assumed that a very small investment is still required. According to available literature[114], the investments is be estimated to be one EUR/kW. No information is provided on the thinking behind the estimation.

To present the costs as yearly costs, an annuity factor is used:

$$\frac{r}{1-(1+r)^{-n}},$$

r : cost of capital, assumed to be 3.5%
n: depreciation period, assumed to be 10 years

This results in an activation cost for industrial demand response of 0.12€/kW/year.

[113] It is possible that other costs, such as labour, are different at the alternative production time, for example because of additional pay for night shifts. The assumption is however that a shift to production hours with higher labour costs do not take place.
[114] Quantifying the costs of demand response for industrial business, Anna Gruber, Serafin von Roon, 2013

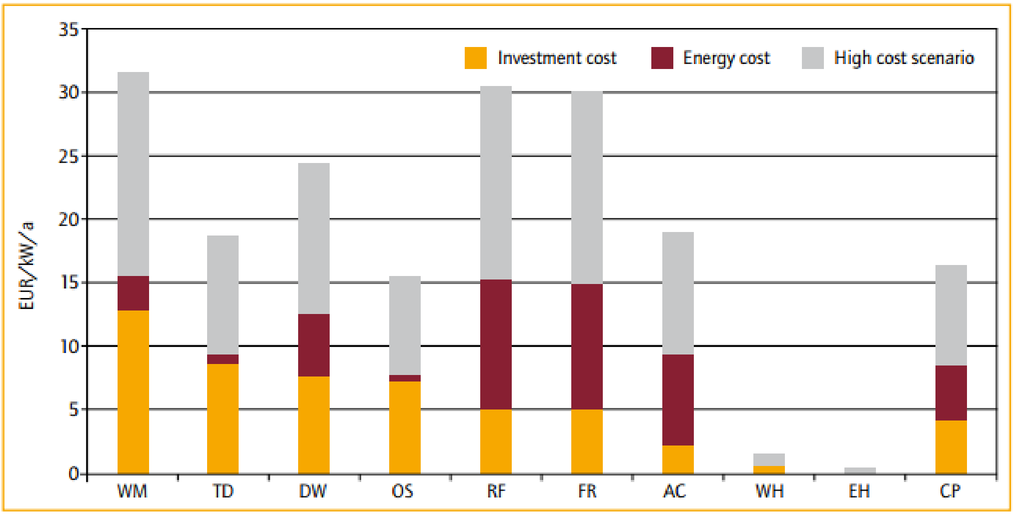
In another article115, the potential of demand response is estimated for residential consumers. To enable demand response for residential consumers, smart appliances must be installed. This means the costs of appliances will be higher. Currently, most new appliances already have an electronic controller which can make the appliance "smart". However, the appliance also has to be equipped with a communication module, which will typically be either a powerline communication (PLC) or a wireless module (such as WLAN or ZigBee). It is assumed that due to mass production of smart appliances in the future, the additional costs will be between 1.70 EUR and 3.30 EUR per year for all appliances that enable smart operation 116.

Furthermore, costs are required for the smart appliance to communicate with a central gateway in a building. This can be integrated into a smart meter or can be offered as a separate device. The gateway enables communication between the residential consumer and an external load manager or aggregator. The link between the appliances and the gateway (powerline or wireless communication) does not require the installation of additional wires.

Small additional costs can be assumed due to electricity consumption as a result of standby mode of smart appliances. This is assumed to increase the electricity consumption of the appliance between 0.1% and 2%. Related to the production cost of electricity, the additional cost for standby consumption range between 0.02 and 0.55 EUR per appliance and year for a moderate energy cost scenario and up to 1.10 EUR per appliance and year for the high energy cost scenario. Finally, an assumption is made on the flexibility per appliance. In Figure 20 the capital costs are given in €/kW/year for different residential appliances.

[115] Smart Domestic Appliances Supporting the System Integration of Renewable Energy, 2009

[116] Stamminger R. (2009b): R. Stamminger, with contributions from G. Broil, C. Pakula, H. Jungbecker, C. Wendker: Strategies and Recommendations for Smart Appliances; a report from the Smart-A project.



Source: Author's own illustration based on Seebach et al 2009

Figure 20: Activation costs of demand response for residential consumers

(WM: Washing Machine, TD: Tumble Dryer, DW: Dish Washer, OS: Oven Stove, RF: Refrigerator, FR: Freezer, AC: Air Conditioning, WH: Electric Water Heater, EH: Electric Storage Heating, CP: Heating Circulation Pump)

For **commercial** consumers, the costs for demand response are not available in the literature. Therefore, the costs are derived from the costs of demand response for residential consumers. Because the electricity consumption of commercial consumers is on average higher than the electricity consumption of residential consumers, more load can be shifted. As a result, investments are lower per kW/year. An assumption is made that the costs for commercial consumers will be a factor 6 lower.

In Table 25 an overview is provided of the costs per consumption and consumer type. These costs are multiplied with the potential demand response per policy option to define the cost of demand response.

Table 25 Costs of demand response per consumption type

Consumption type	Consumer type	Final cost of activation [€/kW/year]
Aluminium	Industrial	0.22
Copper	Industrial	0.22
Zinc	Industrial	0.22
Chlorine	Industrial	0.22
Mechanical Pulp	Industrial	0.22
Paper Machines	Industrial	0.22
Paper Recycling	Industrial	0.22

Consumption type	Consumer type	Final cost of activation [€/kW/year]
Electric Steel	Industrial	0.22
Cement	Industrial	0.22
Calcium Carbide	Industrial	0.22
Air Seperation	Industrial	0.22
Industrial Cooling	Industrial	3.31
Industrial Building Ventilation	Industrial	3.00
Cooling Retail	Commercial	5.81
Cold storage houses	Commercial	3.50
Cooling Hotels/Restaurants	Commercial	3.50
Ventilation Commercial Buildings	Commercial	3.00
AC Commercial Buildings	Commercial	3.31
Storage hot water commercial sector	Commercial	1.00
Electric storage heater commercial sector	Commercial	1.00
Pumps in water supply	Commercial	0.22
Waste water treatment	Commercial	0.22
Residential refrigerators/freezers	Residential	23.25
Washing machines	Residential	24.00
Laundry driers	Residential	14.00
Dish washers	Residential	17.25
Residential AC	Residential	13.25
Storage hot water residential sector	Residential	1.00
Electric storage heater residential sector	Residential	1.00
Residential heat circulation pumps	Residential	11.75
Electric vehicles/batteries	Residential	1.00
Heat pumps	Residential	1.00

In Figure 21, the costs of demand response are visualized per policy option. As can be seen, the costs are mostly related to residential sector. This is a result of the higher price per kW that is required to activate demand response.

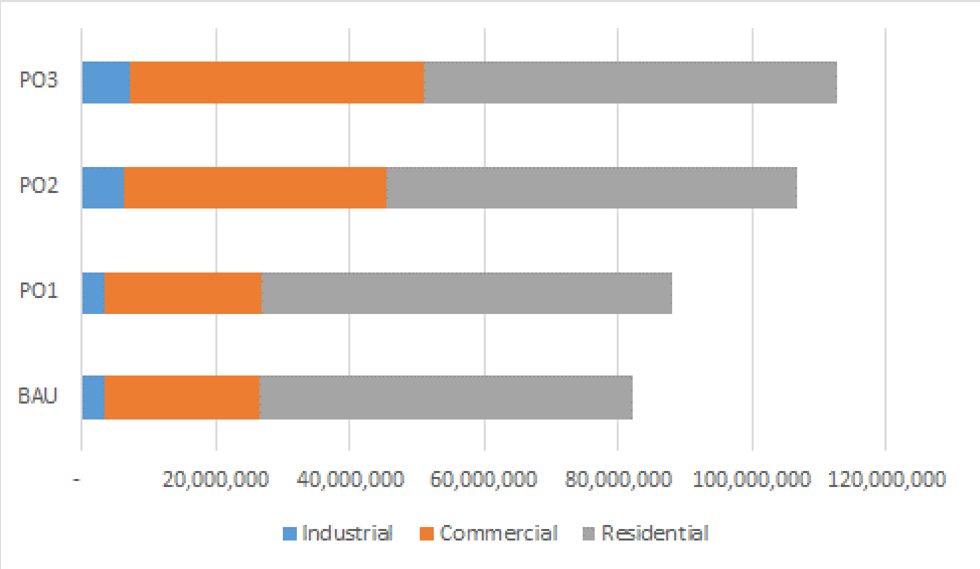


Figure 21 Activation costs of demand response by policy option - 2030

The assessment of the costs have addressed activation costs related to each type of consumer and consumption elements. The costs related to the roll out of smart meters are the other major cost element that need to be considered.

The assumptions for estimation of the costs of smart meters by option:

- BAU: It is assumed that for the Member States that have decided on a full roll out of smart meters based on the positive outcome of the CBA, no costs are included in this assessment.

- Option 1: The costs of the additional meters being installed under Option 1 are estimated using the value of 279 per meter point, see Section 5.2.4. It is further assumed that only half of the costs included as the meter achieve other benefits than those related to demand response effects. Hence, the resulting cost per meter point is assumed to be 140 EUR.

The specific numbers by Member States are presented in the below table.

Table 26 Estimated costs of additional smart meter installation for Option 1

Country	Metering points	Penetration of smart meter by 2030 BAU	Additional meters by Option 1 2030	Cost of meters for Option 1 in MEUR
Austria	5700000	95%	0%	0
Belgium	5975000	0%	40%	333
Bulgaria	4000000	0%	40%	223

Country	Metering points	Penetration of smart meter by 2030 BAU	Additional meters by Option 1 2030	Cost of meters for Option 1 in MEUR
Croatia	2500000	0%	40%	139
Cyprus	450000	0%	40%	25
Czech Republic	5700000	0%	40%	318
Denmark	3280000	100%	0%	0
Estonia	709000	100%	0%	0
Finland	3300000	100%	0%	0
France	35000000	95%	0%	0
Germany	47900000	31%	10%	634
Greece	7000000	80%	0%	0
Hungary	4063366	0%	40%	227
Ireland	2200000	100%	0%	0
Italy	36700000	99%	0%	0
Latvia	1089109	95%	0%	0
Lithuania	1600000	0%	40%	89
Luxembourg	260000	95%	0%	0
Malta	260000	100%	0%	0
Netherlands	7600000	100%	0%	0
Poland	16500000	100%	0%	0
Portugal	6500000	0%	40%	363
Romania	9000000	100%	0%	0
Slovakia	2625000	23%	17%	62
Slovenia	1000000	0%	40%	56
Spain	27768258	100%	0%	0
Sweden	5200000	100%	0%	0
UK	32940000	100%	0%	0
TOTAL	**276819733**	**74%**	**7%**	**2470**

Source: Own calculations based on Table 5-6 and AF Mercados EMI and NTUA (2015)

The total investment and other costs per meter point are annualised over 15 years at 3.5%. The annual costs of Option 1 is therefore estimated at 215 MEUR. The costs of smart meter for Option 2 and 3 are the same as no additional smart meters are assumed for these two Options.

5.10.2 Benefits of options

Introduction

The overall approach to the assessment of benefits focus on the cost savings in the systems – generation and transmission/distribution. These are the "real" welfare benefits. The effects on the different markets might deviate from the real changes depending on the level of competition and market rules. It would require a detailed modelling and simulation of each market to estimate the effects on prices and how these would translate into effects for the different actors. Such an assessment has been outside scope of this study. It should also be noted that the effects on market prices that are not based on the changes to system costs are transfers between stakeholders rather the overall welfare benefits.

To estimate the benefits of demand response options, a simple model is developed by Ecofys within this project. The model determines the effect of demand response on electricity demand and the consequences for electricity generation. The model calculates how the hourly profile of electricity demand changes as a consequence of applying demand response. By using a running average technique, it is determined how much the power peaks in a varying electricity demand can be diminished: How much load can be shifted to a later hour (within the maximum load shift duration)?

In this paragraph, the detailed steps that are taken by the model to obtain the desired results will be described. Note that the model is an approximation in the sense that it determines the theoretical maximal effect that demand response can have on the fluctuating electricity demand. The model does not take into account all kind of detailed interactions that certainly will play a role in practice.

Demand response is expected to decrease the peak demand and thereby the maximum needed backup capacity in the electricity market. The value of a decrease in backup capacity is expressed as a decrease in yearly CAPEX and fixed OPEX as a function of installed capacity.

Demand response also diminishes variable OPEX. When residual electricity demand[117] is averaged (flattened) by demand response, less backup power needs to be generated by backup units high in the merit order, and the variable costs of electricity generation will be reduced.

Together the decrease in fixed and variable costs determine the estimated value of a demand response option in the electricity market.

Calculations

The model calculates the estimated value of demand response using the following steps:

1. Calculate the hourly residual load: the hourly electricity demand minus the hourly electricity generation by intermittent sources.
2. Calculate the generation costs for the residual load. The fixed costs are determined as the peak residual load in GW times the fixed costs in MEUR/year per GW installed capacity. The variable costs are calculated

[117] Residual demand is the demand that remains after subtracting intermittent sources like solar and wind.

by assigning the required backup generation to the different backup technologies according to the merit order[118]. The total costs are the sum of the fixed costs plus the variable costs.

3. Estimate the hourly residual load after demand response that is maximally possible (unlimited by potential in MW, but limited by maximum load shift duration). This is done by calculating the so called running average of the original residual load with a running time window equal in length to the maximum load shift duration.
4. From the difference between the original and the averaged residual load, calculate the decrease in peak load and the shift in total backup generation that can maximally be achieved by demand response with certain maximum load shift duration.
5. Sum the total capacity available for each demand response option with the same maximum load shift duration (input from the same data as was used to construct “Table 24: Total DR potential price + incentive based in 2030 (MW)”).
6. Limit the difference between the original residual load and the averaged residual load obtained in step 3 to the level that is available from the sources identified in step 5. [119]
   Again compare the residual load with the residual load after demand response, but now use the averaged residual load obtained after limiting it by the available demand response power. Calculate the decrease of the maximum power and the shift of the backup generation and determine their corresponding estimated values.
   The value reduction is determined by calculating the generation cost according to the same method as described in step 2, and subtracting these costs from the generation costs for the original residual load.
7. We calculate the value of the demand response options with different maximum load shift duration in a cumulative way, for each possible value of load shift in order. First, for a certain scenario we take all options having a maximum load shift duration of 1 hour and calculate the residual load after demand response and the corresponding value reduction, using the summed DR power for those options as a power limit.
   Next, we take the residual load that resulted after applying the demand response with a maximum load shift of 1 hour, and we apply the demand response procedure to *this* residual load, while using the next value of maximum load shift duration (3 hours).
   We repeat this process for all values of maximum load shift duration and calculate the value in a cumulative way.
8. The calculations are repeated for the different demand response scenarios.

[118] This means the capacity with the lowest marginal costs are fully deployed first, minimizing the operational costs.
[119] This is an approximation to the demand response procedure in practice. Using our approximation, the total electricity demand after demand response can differ somewhat from the total load before DR (but the difference < 0.3%).

The benefits of demand response can also be found in reduction of CO2 emissions. To calculate the change in CO2 emissions we follow the following steps:

- Determine the CO2 emission factor for each backup technology in the merit order.

- Using the intermediate results from the calculations step 2 when determining the generation costs, we can extract the total generation for each backup technology.

- For each technology, multiply its total generation by its CO2 emission factor, thus calculating the CO2 emissions per technology. Adding up those emission results in the total CO2 emissions.

- Compare the total CO2 emissions after applying demand response options with the CO2 emission without having demand response. The decrease of the emission gives us the CO2 benefit of applying demand response.

Inputs

To run the model calculations the following inputs are being used (all for region EU28):

1. The hourly electricity demand profile for 2030[120]. The total electricity demand of this profile is 3576 TWh; the maximum demand is 570.7 GW.
2. The hourly renewable generation for 2030[120]. The total renewable generation is 1796 TWh; the minimum renewable generation is 99.6 GW.
3. The total capacity of backup plants per technology as shown in Table 27. The total backup capacity is 453.6 GW. A part of the backup power is generated by run of river hydro power.
4. The price of electricity generation (based on fuel + carbon costs) for calculating variable costs. Run of river hydro variable cost are neglected. The merit order of the available backup technologies is shown in Figure 22.
5. For calculating fixed costs for plants, we assume CAPEX plus fixed OPEX to be equal to 54 plus 32 is 86 MEUR/year per GW installed capacity.
6. The total power of DR potential in MW per maximum load shift duration is obtained from the same data as was used to construct “Table 24: Total DR potential price + incentive based in 2030 (MW)” for each scenario.

[120] European electricity demand and renewable generation for 2030 is taken from: Ecofys (2013): *Impacts of restricted transmission grid expansion in a 2030 perspective in Germany*.

Table 27 Backup technologies, capacities and prices[121].

Technology	Capacity (GW)	Price (€/MWh)
Hydro	70.0	0.00
Nuclear	89.9	11.1
Lignite	20.4	41.4
Coal	53.4	43.6
Gas CCGT	154.7	45.8
Gas OCGT	38.7	68.0
Oil	26.5	124.9

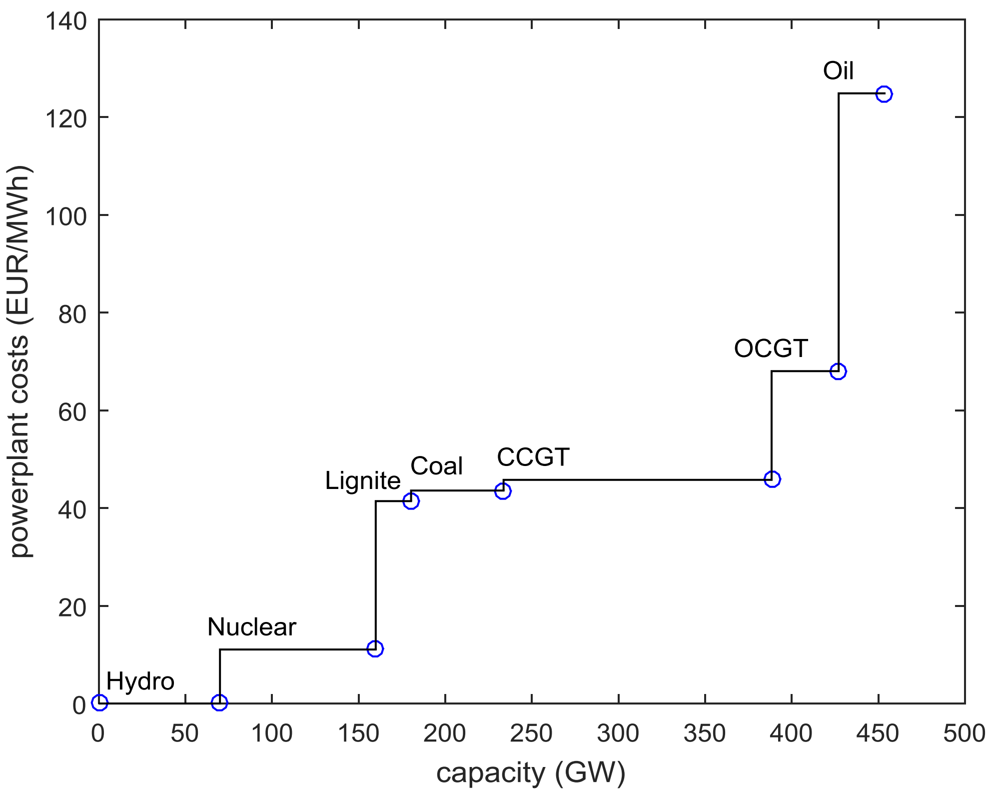


Figure 22 Merit order of backup capacity.

Results

The value of the demand response options for the different scenarios is calculated according to the steps described in the paragraph Calculations above.

---

[121] Power plant capacities are taken from scenario B of the ENTSO-E adequacy forecast 2014. Prices are from: Ziems, Christian; Meinke, Sebastian; Nocke, Ing Jürgen; Weber, H.; Hassel, E. (2012): *Kraftwerksbetrieb bei Einspeisung von Windparks und Photovoltaikanlagen.* In: VGB Powertech, Tech. Rep. Online verfügbar unter http://www.vgb.org/vgbmultimedia/333_Kurzbericht-p-5972-preview-1.pdf. The fuel prices include CO2 tax of 25 €/ton.

First, the residual load is calculated. The total residual volume becomes 1780 TWh, and the maximum residual load is 419.7 GW, while the minimum residual load is -16.1 GW. This minimum only occurs for very few hours as we can see in Figure 23. The figure shows the duration curve of the residual load. We conclude there is very little curtailment of renewable sources.

Subsequently all model calculations steps as described before are carried out, and the value of the demand response options is determined. As an example of intermediate results, Figure 23 shows the duration curves of the residual load after averaging without power limit (‘ResLoad avg’) and with power limit of 4.7 MW (‘ResLoad avg lim’). We can observe the decrease in the peak of the residual load and the shift of the backup generation power from backup technologies high in the merit order to less expensive technologies.

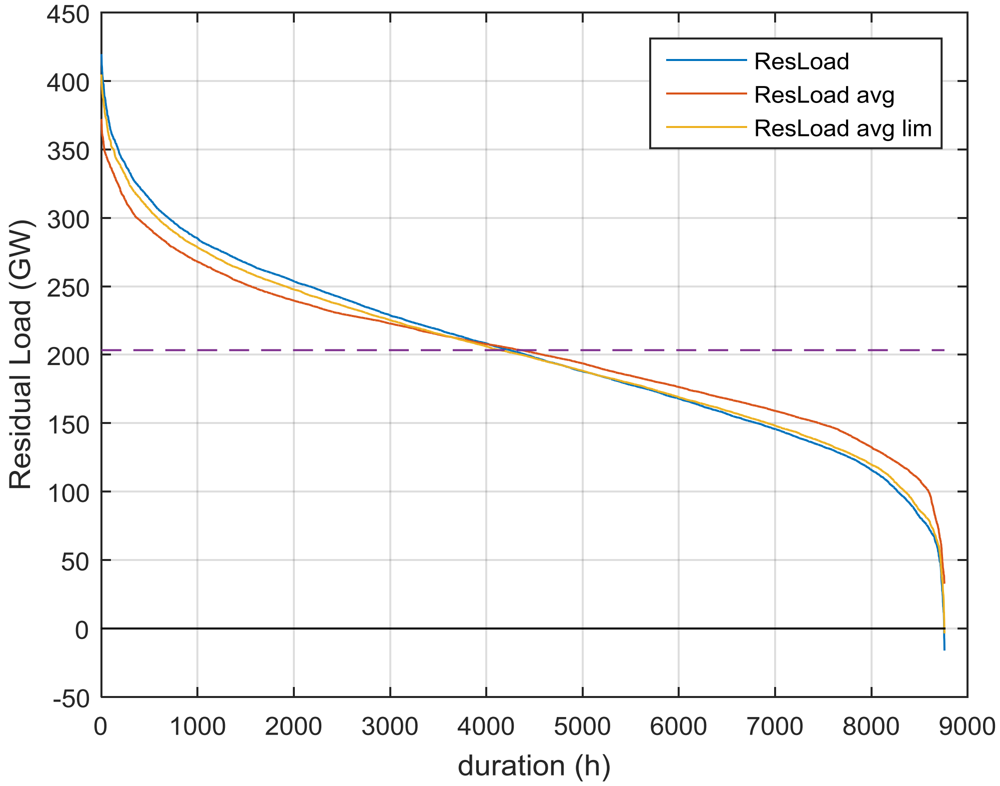


Figure 23. Load duration curves of residual load, residual load averaged for maximum load shift duration of 12 hours, and residual load after additionally limiting by maximum demand response power of 4.7 MW. The original, unaveraged residual load has a peak value of 419.7 GW and for this residual load profile an amount of 1780 TWh of backup electricity needs to be generated. When the residual load profile is averaged (flattened) by demand response, less backup power needs to be generated by backup units high in the merit order.

The results are presented in the following tables. In Table 28 the results are shown for the case when the demand response would not be limited by available DR power. The total value in this table represents the maximum achievable value of demand response estimated by this model.

Table 29 shows the results for the business as usual (BAU) scenario. Each row in the table shows for the indicated maximum load shift duration and the corresponding total available demand response power what the cumulative decrease in peak backup power is estimated to be, and what its cumulative value up to that row is. Also shown are the estimated cumulative value due to shift in backup generation and the estimated total cumulative demand response value.

Thus, the first row in the table shows the effect of applying all demand response options with a maximum load shift duration of 1 hour. The second row shows the cumulative effect of additionally applying DR with maximum load shift duration of 3 hours. This result is obtained after having determined the effect of the 1 hour options, and starting from that situation, now also applying the 3 hour load shift options, to determine what the total, cumulative effect of all options will be. We continue adding extra demand response options with increasing maximum load shift duration and calculate the cumulative effect for each step.

Table 28. Demand Response potential with unlimited Demand Response power.

Maximum Load Shift Duration (h)	Cumulative Peak decrease residual load (GW)	Cumulative Value of peak decrease (MEUR/y)	Cumulative Value of generation shift (MEUR/y)	Total Cumulative Value DR option (MEUR/y)
1	2.3	197	75	272
3	18.7	1608	385	1993
6	37.9	3252	940	4192
12	54.7	4700	1400	6101
24	78.8	6774	1768	8541

Table 30, Table 31, and Table 32 show the same results, but for the policy option 1, 2, and 3 (PO1, PO2, PO3) scenario. They cover the effect of price based and incentive based demand response.

Table 29. Demand Response potential for BAU scenario.

Maximum Load Shift Duration (h)	DR potential 2030 (MW)	Cumulative Peak decrease residual load (GW)	Cumulative Value of peak decrease (MEUR/y)	Cumulative Value of generation shift (MEUR/y)	Total Cumulative Value DR option (MEUR/y)
1	10895	2.3	197	309	506
3	12509	14.8	1273	884	2156
6	2966	17.8	1528	983	2511
12	7187	25	2146	1255	3401
24	813	25.8	2216	1302	3517

Table 30. Demand Response potential for PO1 scenario.

Maximum Load Shift Duration (h)	DR potential 2030 (MW)	Cumulative Peak decrease residual load (GW)	Cumulative Value of peak decrease (MEUR/y)	Cumulative Value of generation shift (MEUR/y)	Total Cumulative Value DR option (MEUR/y)
1	11076	2.3	197	308	504
3	14609	16.9	1453	947	2400
6	2981	19.9	1710	1040	2749
12	7305	27.2	2338	1309	3647
24	879	28.1	2413	1359	3772

Table 31. Demand Response potential for PO2 scenario.

Maximum Load Shift Duration (h)	DR potential 2030 (MW)	Cumulative Peak decrease residual load (GW)	Cumulative Value of peak decrease (MEUR/y)	Cumulative Value of generation shift (MEUR/y)	Total Cumulative Value DR option (MEUR/y)
1	17843	2.3	197	184	381
3	17160	18.9	1625	896	2522
6	5633	24.6	2110	1064	3174
12	10922	35.5	3049	1417	4466
24	879	36.4	3125	1464	4588

Table 32. Demand Response potential for PO3 scenario.

Maximum Load Shift Duration (h)	DR potential 2030 (MW)	Cumulative Peak decrease residual load (GW)	Cumulative Value of peak decrease (MEUR/y)	Cumulative Value of generation shift (MEUR/y)	Total Cumulative Value DR option (MEUR/y)
1	19985	2.3	197	145	342
3	17913	18.7	1608	870	2479
6	6420	25.2	2161	1060	3220
12	11920	37.1	3186	1430	4616
24	879	38	3261	1475	4736

Table 33 shows the summary of the total potential and total benefits for all demand response options for the different scenarios.

Table 33. Summary of demand response potential and demand response benefits for the different scenarios. Also shown are the CO2 benefits for each scenario.

Scenario	Total DR potential 2030 (MW)	Total Value DR options (MEUR/y)	Total CO2 benefits (Mton/y)
BAU	34371	3517	12.4
PO1	36850	3772	13.0
PO2	52438	4588	12.7
PO3	57117	4736	12.4

Table 33 also presents the results of the CO_2 benefits calculations. For each scenario, the decrease in CO_2 emission resulting from having demand response applied is shown.

The total CO_2 emission without any DR is 371 Mton/year. From the table we see that the CO_2 reduction potential from DR is about 3.4%. We can explain why this number is not higher. As we saw before, there is little curtailment of intermittent RES. If no RES is being curtailed then load shifting will only move electricity generation from one fossil fuel to another fossil source. We see that for a scenario like PO3, the CO2 benefits are less than for other options, even if its total DR potential is higher. This can be explained as follows. By applying DR, the peak demand will be diminished and less power is generated by backup units high in the merit order (e.g. gas plants). But at the same time some low demand values will become higher after DR is implemented (we assume the total demand does not change) and more power is generated by backup units lower in the merit order (e.g. lignite plants). For the specific case of scenario PO3 relatively much power generation is shifted to lignite plants, and CO2 benefits are less because of the high CO2 generation per MWh for lignite plants.

When considering these results it is important to keep in mind that interconnections between countries are assumed to be unlimited . While indeed the interconnectivity between EU countries will grow substantially, it is likely that some congestion will remain. In case of congestion, peak capacity of a neighbouring country cannot be used, which means that either the infrastructure must be upgraded or additional peak capacity has to be created in the demand side of the congestion. Demand response can help to lower the need for either of these solutions.

Overall, the benefits per MW of Demand Response potential found in the model are the same order of magnitude as seen in previous studies. In a recent study of Ecofys into Demand Side Management it was found that a MW of demand response could save about 25.000 €/y, against 80.000 €/y found in this study. The difference can be explained by the prioritisation of congestion management in the former study.

5.10.3 Distribution grids

In the distribution grids, demand response options can be deployed to reduce the peak, and thereby the required capacity, in the distribution and transmission networks. These benefits are reflected in a lower required investment in these grids.

The benefits shown in the column ‘distribution and transmission’ in the table below are estimated based on existing literature on this topic in combination with the calculations of the overall possible peak reduction as calculated for the system level. It is shown in modelling exercises that to a large extent peak reduction at the system simultaneously reduces peaks in the distribution grids.[122] This makes this peak demand reduction a good starting point for estimating the savings in the grids.

To estimate the savings per kW of peak capacity reduced, we need to distinguish between demand connected on the lower voltage and higher voltage grids. The savings on the higher voltage are lower because only investments in transmission can be avoided. We have assumed that industrial demand is on the higher voltage grids, while domestic and commercial demand response is connected to the medium or lower voltage grids. To estimate the savings per kW, we have assessed, per policy option, which share of the demand response is on what grid level to estimate the average grid savings per kW. These costs are shown below.

Table 34 Transmission and distribution network benefits

	Share in % industrial	Share in % commercial + residential	Transmission connection costs (€/kW/y)[123]	Distribution connection costs (€/kW/y) [124]	Average (€/kW/y)
BAU	10	90	65	35	38
PO1	10	90	65	35	38
PO2	11	89	65	35	38
PO3	11	89	65	35	38

The average savings above are used to calculate the savings that are made possible by the peak reduction in the paragraph above. The results are presented in Table 35 below.

[122] http://nbn-assets.netbeheernederland.nl/p/32768//files/Rapport%20Waarde%20van%20Slimme%20Netten%20Ecofys.pdf

[123] TenneT System integration study
[124] TenneT and MW costs
http://nbn-assets.netbeheernederland.nl/p/32768//files/Rapport%20Waarde%20van%20Slimme%20Netten%20Ecofys.pdf

Table 35 Benefits of demand response in the distribution and transmission grid for each scenario.

Scenario	Peak decrease (GW)	Total benefit DR in distribution and transmission grid (MEUR/y)
BAU	25.8	980
PO1	28.1	1068
PO2	36.4	1383
PO3	38.0	1444

5.10.4 Distribution of costs and benefits

The assessment of costs and benefits have provided an indication of the levels of costs for activating the demand response and the benefits to system of increased demand response.

The distributional impacts cannot be estimated in quantitative terms. It will depend on the specific market situations and the market prices that will be established.

To illustrate the possible effects and in particular the issue of compensation of the BRPs from the aggregators, the following example can be presented.

Based on the historic data of a random month of historic imbalance and day-ahead prices[125], we can derive what the compensation effects will be if an aggregator shift their demand. We assume that an aggregator lowers the demand in their portfolio 5% of the time.[126] Per MW, this would create a revenue of 82 thousand euros per year. These are the sales on the imbalance market. The compensation based on APX prices for these hours would amount to roughly 18 thousand euros (the compensation for that volume against day-ahead). This would be costs for the aggregators, amounting to 22% of the revenues.

This outcome is highly dependent on the strategy of the aggregator. If the aggregator would respond to any imbalance price incentive, the compensation would go up to 53%, as the difference between day-ahead and imbalance is on average lower. This means that not having to pay compensation would make the aggregator ‘over-respond’ to price incentives as basically he is selling electricity he is not paying for. That would mean that also the aggregator’s clients would find themselves being curtailed more often than is optimal for the system. This is also results double costs for the system – the aggregator is paid by the TSO, and so is the balancing responsible party as it automatically sells the (administrative) surplus of electricity into the balancing market at likely higher prices than APX (as the aggregator only curtails at moments of high imbalance prices. In the end, the TSO

---

[125] Actual data of imbalance prices and day-ahead prices in the Dutch APX and TenneT imbalances markets from December 2011 (44462 minutely values)

[126] This means they lower demand if imbalance prices are above 126 euros per MWh

(administratively) buys twice the volume. This would be avoided if the aggregator bought the energy from the supplier and sold it on.

The example suggests that:

- With compensation the incentive structure is more efficient
- With compensation (through purchase of the electricity from the supplier to the aggregator), the system costs would be lower.
- With compensation, there is still significant income for demand aggregators if they are careful when to use their flexibility.

The specific allocation of the revenue among the actors depend on many factors. The above example is just one way that specific compensation could be made. The details of the specific rules for compensation, the prices at the markets, the tariff schemes for the consumers will determine the final distribution of costs and benefits.

A qualitative assessment has been made. The assessment in the previous section has estimated the net system benefits, which are a comprised of the reduced cost for back-up generation and transmission and distribution network capacity. The qualitative assessment considers how these costs savings could be distributed. It also considers the effects of lower prices on the markets due to the reduced peak demand. At peak demand, the intra-marginal generation earns a profit. In economic terms, it is the producer's surplus and with reduced demand, there is reduction in producer's surplus. Part of this offs-set by increase in consumer's surplus.

Qualitatively, the following "winners" and "losers" can be identified.

Table 36 Costs and benefits of policy options for 2030

Actor	Option 1	Option 2	Option 3
Generators	Will lose profit on intra marginal generation at peak load	Will lose profit on intra marginal generation at peak load	Will lose profit on intra marginal generation at peak load
Network operators	Reduced need for investment – no change in profits	Reduced need for investment – no change in profits	Reduced need for investment – no change in profits
Suppliers	Potentially, reduced risks as consumers reduce peak load demand where wholesale prices are high and exceeding the retail prices.	As Option 1 plus effect from more even wholesale prices. Both gains and losses.	As Option 2 though possible larger effects on wholesale prices.
BRP	No change	No change	Will lose on extra balancing costs (increased financial risk)
Aggregators	No change	Increased business opportunities	Increased business opportunities (more than in

Actor	Option 1	Option 2	Option 3
			option 2)
Consumers	Reduced electricity bill	Reduced electricity bill (more than in option 1)	Reduced electricity bill

For aggregators the scope of opportunities depends on the details of the compensation rules. There will be a better business case without compensation, but the additional profit will come at a loss to retailers and potentially higher system costs to be covered by the consumers.

Overall, the main "loser" will be the generators that earn high intra marginal profits on the generation at peak times where the prices are high.

For suppliers, it is difficult to predict the effects without very specific simulations of the markets. For price based demand response to be activated, consumers need to have some form of dynamic price contracts. Whether the effects of such contracts and the resulting demand changes will affect the supplier will depend on the specific contracts and the changes in demand. If the consumers have RTP contracts, the effects for the suppliers are not likely to be very significant assuming that their profit is the same on all electricity sold. If the wholesale prices at the highest peaks exceed the retail prices, there will be gain if price based demand response moves demand away from these high peaks.

Incentive based demand response will reduce the wholesale prices at peak demand and increase them at off peak times. Price based demand response will also reduce the wholesale prices over time, as consistently lower retail demand in peak hours must lead to suppliers demanding less electricity in peak hours on wholesale markets – and vice versa for off peak. Again, the effects depends on the specifics, such as the contracts that the consumers have with the supplier. It is likely that the overall effect will be limited for the suppliers.

The winners will be the consumers that see lower electricity costs. The aggregators and the consumers will share the part of the gain that derives from the incentive based demand response.

6 Comparison of options

This section presents a comparison of the alternative policy options. It is based on the impacts estimated and discussed in the previous Chapter 5.

Overall, the assessment is very complex given that many factors are in play. These factors include future technological developments in home automation and storage, developments on the energy markets, as well as the situation in each Member State regarding the details of electricity market design and regulation.

The approach to the assessment of the policy options has included the following elements:

- Assessment of a theoretical potential for demand response
- Assessment of the current level of demand response
- Assessment of how each option is likely to increase the share of the theoretical potential being realised
- Estimation of the costs and benefits of the options

The theoretical potential is based on an assessment of the nature of the electricity use by industrial, commercial and residential consumers. This measure represents the maximum potential for shifting demand, and refers to a shift in demand (load shifting, peak shaving and valley filing). It is not assumed that total demand will be reduced.

Through review of studies and data on the current demand response, an estimate of the current level of demand response is computed and that is used as basis for the BAU development up to 2030.

Table 40 presents the key assumptions on the theoretical demand response potential and how much is activated under the BAU measures as capacity and in percentage of peak load.

Table 37 Theoretical potentials, peak load and BAU estimates (GW)

Capacities	**2016**	**2020**	**2030**
Peak load (current and estimated)	486	500	568
Total maximum theoretical DR potential In % of peak load	110 22%	120 24%	160 28%
BAU In % of peak load	21 4.3%	23 4.6%	34 6.0%

Source: Own calculations based on Gils (2014) and Entso-E

While it might not be possible to activate all the total theoretical potential, the current level of demand response is limited. Hence, there is a need to consider the effectiveness and efficiency of options to increase the level of demand response.

The study has considered how current level of demand response would develop based on the existing legislation and measures. Many factors influence the BAU estimate. They include:

- The roll out of smart meters and use of dynamic price contracts
- The availability of home automation
- The availability of behind the meter storage
- The national regulations and market design
- The incentives for demand response (variability of prices on the different markets)

The complexity of these factors and interaction means that prediction of the 2030 situation inevitably will be subject to large uncertainty. The technical potentials could increase or reduce the BAU uptake of demand response.

What is a main point for the definition and assessment of policy options is that removing barriers for an effective and efficient use of demand response will be important no matter the exact volume of demand response.

The assessment of the current situation (see Section 2 and 3) has identified many of the barriers for demand response. They can be grouped into the following categories:

- Consumer's ability to react (meters, tariff structure and knowledge)
- Market design and regulation (access rules and incentives)

To overcome these barriers, the following policy options has been defined:

› <u>Option 1</u>: Demand response is promoted by legislation that gives all EU consumers access to smart meters and dynamic pricing contracts.

› <u>Option 2</u>: Demand response is promoted by legislation that gives all EU consumers access to dynamic pricing contracts and standardised EU market rules for demand response service providers.

› Option 3: As Option 2 but where the demand response service provider has the right to offer its services without compensation to the retailer/BRP.

Section 5 presents the detailed assessment of the impacts and effects of the alternative policy options.

In this section, the options are compared with regard to the following criteria:

- Effectiveness (how much additional demand response is achieved)
- Efficiency (cost-benefit of each option)
- Coherence (how the options fit with EU policies in particular the Energy Union objectives)
- Distributional effects (assessment of how the different stakeholders will be affected)

6.1 Assessment of the effectiveness of the options

The alternative policy options will increase the uptake of demand response. The main assumptions on how they will do that are summarised below.

6.1.1 Option 1

This option is about giving all consumers right to require a smart meter and a dynamic price contract. These elements are a pre-condition for the consumer to act on the price differentials and shift or reduce his/her demand.

Key assumptions:

- Price based demand response: Limited additional uptake of meters and dynamic price contracts
  - An increase of consumers with smart meters in BAU from 71% in 2020 and 74% in 2030 to 81% in 2030 under Option 1. The increase is concentrated in the Member States without a general roll out of smart meters.
  - A small increase in the take-up of dynamic price contracts leading to an overall increase in the demand response for all consumers. It is assumed that the share of consumers with critical peak pricing schemes increase from 16% to 18%. The share of consumers with static TOU tariffs remains that same in Option 1 as in the BAU situation with 26%.
  - Where customers opt for a smart meter in a Member State without a large scale roll-out, they will to a larger extent request dynamic

pricing contracts leading to an additional increase in demand response.

- Incentive based demand response

    - There is no increase in incentive based demand response. In principle, the additional smart meter uptake could support more, but the main conditions for the incentive based demand response are not changed and therefore no additional demand response is expected.

Based on these assumptions, the demand response resulting from Option 1 is estimated and the results displayed in Tables 41-43 below.

6.1.2 Option 2

Option 2 is about allowing incentive based demand response by defining standardised rules for how demand response can enter the different energy and capacity/balancing markets.

The main elements that increase the uptake of incentive based demand response are:

- Removal of barriers that prevent incentive based demand response participation in wholesale markets, besides allowing such participation, include:

    - To ensure that demand participates at a level playing field with generation
    - To reduce the market resolution (i.e. from hourly to 15 minutes or less)
    - To move market closure closer to the operation hour
    - To extend the number of bidding possibilities to take account of the wider range of heterogeneity on the demand-side
  - Allowing aggregated bids when possible

- Concrete measures to incentivise DR participation in balancing markets are:

    - Reduce minimum bid volumes to allow for smaller loads to participate
    - Adjust bid size, duration, recovery time, response time, etc. to fit the demand side
  - Set up standard processes and settlement between aggregators and suppliers

The level playing field is ensured by either of the following type of compensation rule:

    - The suppliers integrate aggregated DR as part of their service offering
    - The aggregator and supplier must bilaterally settle imbalances and costs based on a standard contract
    - The aggregator must take on a second balance responsibility for activated loads

The assessment has considered each of the models for compensation and while in the long term integration of the supplier and aggregator would provide the proper incentive, it requires that there is no vertical market integration between generators and suppliers. Hence, the second model is likely to be more feasible.

Based on removing the above barriers for incentive based demand response, the effects are estimated:

- Price based demand response
    - No change compared to Option 1
- Incentive based demand response
    - The introduction of standardised rules for demand aggregation is assumed to increase the uptake in Member States where there is currently limited or no incentive based demand response. It is assumed that part of the demand response potential from industrial consumers will be included.
    - For Member States that already have incentive based demand response participation in the markets uptake will increase and it is assumed that demand aggregators participate in the markets with the demand response from industrial consumers and part of the commercial consumers.

Based on these assumptions, the demand response resulting from Option 2 is estimated and the results displayed in Tables 41-43 below.

6.1.3 Option 3

Option 3 is similar to option 2 except there is no compensation for the imbalances that the independent aggregators might create. Therefore, the amount of incentive based DR is assumed to be higher as the business model for aggregation is more attractive.

- Price based demand response
    - No change compared to Option 1

- Incentive based demand response
    - The estimation is assuming the under Option 3 the aggregators will in addition to what is included in Option 2 include much of the commercial sector. As there is no compensation, the business case for the aggregators allow for providing service to consumers with lower demand. This is assumed to include the majority of commercial consumers.

Based on these assumptions, the demand response resulting from Option 1 is estimated and the results displayed in Tables 41-43 below.

6.1.4 Comparison of effectiveness

The estimated increase in price and incentive based demand responses are presented in the below tables.

Table 38 Estimated price based demand response of the alternative policy options (GW)

Capacities		**2016**	**2020**	**2030**
	Industrial	0.0	0.0	0.0
	Commercial	1.5	1.6	1.9
	Residential	4.2	4.8	13.4
Total BAU		5.8	6.4	15.4
	Industrial	0.0	0.0	0.0
	Commercial	1.5	1.7	2.1
	Residential	4.2	5.2	15.8
Option 1		5.8	6.9	17.9
	Industrial	0.0	0.0	0.0
	Commercial	1.5	1.7	2.1
	Residential	4.2	5.2	15.8
Option 2		5.8	6.9	17.9
	Industrial	0.0	0.0	0.0
	Commercial	1.5	1.7	2.1
	Residential	4.2	5.2	15.8
Option 3		5.8	6.9	17.9

It is important to note that the assessment has been based on the overall effects. The activation of the demand response potential by the three consumer groups are assumed in order to simplify the calculations. It means that while the largest share of incentive based demand response will come from industrial and commercial consumers, also some activation for residential consumers could take place.

Table 39 Estimated incentive based demand response of the alternative policy options (GW)

Capacities		**2016**	**2020**	**2030**
	Industrial	8.8	9.0	10.3
	Commercial	6.9	7.3	8.7
	Residential	0.0	0.0	0.0
Total BAU		15.6	16.3	19.0
	Industrial	8.8	9.0	10.3
	Commercial	6.9	7.3	8.7
	Residential	0.0	0.0	0.0
Option 1		15.6	16.3	19.0
	Industrial	8.8	11.2	18.6
	Commercial	6.9	9.1	15.9
	Residential	0.0	0.0	0.0
Option 2		15.6	20.3	34.6
	Industrial	8.8	11.8	21.0
	Commercial	6.9	9.7	18.2
	Residential	0.0	0.0	0.0
Option 3		15.6	21.4	39.3

Table 40 Estimated total demand response of the alternative policy options (GW)

Capacities		**2016**	**2020**	**2030**
	Industrial	8.8	9.0	10.3
	Commercial	8.4	8.9	10.6
	Residential	4.2	4.8	13.4
Total BAU		**21.4**	**22.7**	**34.4**
	Industrial	8.8	9.0	10.3
	Commercial	8.4	9.0	10.7
	Residential	4.2	5.2	15.8
Option 1		**21.4**	**23.3**	**36.8**
	Industrial	8.8	11.2	18.6
	Commercial	8.4	10.8	18.0
	Residential	4.2	5.2	15.8
Option 2		**21.4**	**27.2**	**52.4**
	Industrial	8.8	11.8	21.0
	Commercial	8.4	11.4	20.3
	Residential	4.2	5.2	15.8
Option 3		**21.4**	**28.4**	**57.1**

The increased use of demand response has many positive effects. The main effects to reduce the need for back-up capacity. It means that it will be possible to include more RES on the generation side, that investment in back-up generation capacity is reduced, and there is increased security of supply. The effect on the reduced need for back-up capacity has been quantified in Section 5. The results are summarized below under the efficiency criteria.

The reduced need for non-renewable back-up generation also means that less energy is produced using non-renewable sources. This means lower emissions. The impact on CO_2 emissions are presented in the below table.

Table 41 Impact on CO_2 – reduction in emissions

Reduction in CO_2 emissions in Mton/y	2030
BAU	12.4
Option 1	13.0
Option 2	12.7
Option 3	12.4

Source: Own calculations

The effect on CO_2 is estimated at around 3.4% of the total emissions. The EU28 annual load curve implies relatively limited curtailment of RES and therefore, the emission effects are from changing between different types of fossil fuel based back-up technologies. Hence, the level of reductions are relatively modest.

6.2 Assessment of the efficiency of the options

The cost and benefits of the options have been estimated. The costs are defined as the activation costs for the different consumption elements.

The benefits are determined as the reduced need for back-up capacity. A year load curve for EU28 is computed and the effects of demand response in smoothing the curve is estimated.

Then the effects on the transmission and distribution network is added to the benefits of reduced peak generation.

The results of the assessment of the costs and benefits are summarised below.

Table 42 Costs and benefits of policy options for 2030 in MEUR per year

MEUR/y	Costs	Benefits			Net benefit
		Network	Generation	Total	
BAU	82	980	3,517	4,497	4,415
Option 1	303	1,068	3,772	4,840	4,537
Option 2	322	1,383	4,588	5,971	5,649
Option 3	328	1,444	4,736	6,180	5,852

Using the approach described above the additional net benefits of the alternative policy options compared to BAU amounts to about 120 MEUR/y for Option 1, 230 MEUR/y for Option 2 and around 1,440 MEUR/y for Option 3. The net benefit refers to the estimated savings in generation and network capacity minus the costs of meters and activation.

What is not included in the estimation of the benefits are the possible effects on system costs, if the independent demand aggregators are free riders and activate the demand response in an inefficient way. One example could be not bidding in the wholesale market but in the balancing markets where the price might be higher. In Option 3 where there is no compensation, the aggregators have no incentive to achieve balance as early as possible in order to improve the overall efficiency.

The follow-on or indirect effects depend on how the savings are distributed among the different actors. The majority will go to the lower electricity bills for the consumers and some to the aggregators. Lower electricity costs will increase welfare for the residential consumers and increase competitiveness for industrial and commercial consumers.

6.3 Assessment of the coherence of the options

Providing more demand response is a key part of the objectives for the EU's energy policy. It is important for allowing more RES into the European electricity system without having to make large investments in conventional back-up capacity.

Option 1 supports the actions on increasing efficiency of the energy system by introducing smart meters and dynamic pricing. As described in more detail in Section 3.1.1, the third energy package of 2007 included promotion of smart meters by requesting Member States to undertake a cost-benefit analysis of smart meters and where the benefit-cost ratio is positive to roll out smart meters. Option 1 means also in Member States where there is no general roll out, relevant consumers can ask for the smart meter and the dynamic price contract. It provides the framework for taking advantage of the technological developments. If intelligent appliances become more available, more electric vehicles, more behind the meter storage etc., then consumers who can benefit from smart metering and dynamic pricing can do so.

Option 2 is specifically addressing incentive based demand response. It is an important part of the Energy Efficiency Directive to promote demand flexibility. Article 15 includes requirements for promotion of demand response. Option 2 is based on the assessment that currently demand response is still not sufficiently included in the national markets and therefore additional action is required. The option is about allowing demand aggregation and also independent demand aggregators equal access to the different electricity markets. The included compensation rules provide the aggregator with balance responsibility that prevents inefficiencies.

Option 3 implies the same access for demand aggregation as Option 2, but does not include any compensation in relation to BRPs. This introduces a possibility of demand aggregators being free-riders in the markets and therefore creating inefficiencies. This is not in line with the EU target model and generally not in line with creating level playing field for competition.

6.4 Assessment of the distributional effects of the options

The distributional impacts cannot be estimated in quantitative terms. It will depend on the specific market situations and the market prices that will be established.

Qualitatively, the following "winners" and "losers" can be identified.

Table 43 Costs and benefits of policy options for 2030

Actor	Option 1	Option 2	Option 3
Generators	Will lose profit on intra marginal generation at peak load	Will lose profit on intra marginal generation at peak load	Will lose profit on intra marginal generation at peak load
Network operators	Reduced need for investment – no change in profits	Reduced need for investment – no change in profits	Reduced need for investment – no change in profits
Suppliers	Potentially, reduced risks as consumers reduce peak load demand where wholesale prices are high and exceeding the retail prices.	As Option 1 plus effect from more even wholesale prices. Both gains and losses.	As Option 2 though possible larger effects on wholesale prices.
BRP	No change	No change	Will lose on extra balancing costs (increased financial risk)
Aggregators	No change	Increased business opportunities	Increased business opportunities (more than in option 2)
Consumers	Reduced electricity bill	Reduced electricity bill (more than in option 1)	Reduced electricity bill

For aggregators, the scope of opportunities depends on the details of the compensation rules. There will be a better business case without compensation, but the additional profit will come at a loss to BRPs and potentially higher system costs to be covered by the consumers.

Overall, the main "loser" will be the generators that earn high intra marginal profits on the generation at peak times where the prices are high. The winners will be the consumers that see lower electricity costs. The aggregators and the consumers will share the part of the gain that derives from the incentive based demand response. The effect on suppliers are difficult to estimate. There could be gains from reduced wholesale prices at peak demand. On the other hand, if wholesale prices off peak increase, then this could result in a loss. Overall, the effect would depend on the specific contracts between suppliers and consumers and the precise changes in wholesale prices.

6.5 Overall comparison of options

The impacts of the alternative policy options are summarised in the table concerning each of the assessment criteria. This is a simple qualitative scoring based on the assessment above.

Table 44 Costs and benefits of policy options

	Effectiveness	Efficiency	Coherence
Option 1	+	+	++
Option 2	++	+++	+++
Option 3	+++	+	-

Note: + means positive effect of increasing magnitude

Option 3 is achieving a higher demand response than Option 1 and 2 and therefore more effective. The low scoring of Option 3 with regard to efficiency is due to risk of the introducing inefficiencies in the balancing markets. Coherence is highest for Option 2 as it allows both price and incentive based demand response to be realised while adhering the EU policy objectives for internal markets and fair competition.

Appendix A Bibliography

ACER, *Recommendation on the network code on electricity balancing*, July 2015.

ACER, *Demand side flexibility: the potential benefits and state of play in the European Union*, 2014

AF Mercados EMI and NTUA, *Study on cost benefit analysis of Smart Metering Systems in EU Member States, Final Report*, 2015.

Address, *Description of market mechanisms (regulations, economic incentives and contractual structures) which enable active demand participation in the power system*, May 2011

Brattle, *International Review of Demand Response Mechanisms.* Prepared for Australian Energy Market Commission, October 2015

AECOM for Ofgem, *Energy Demand Research Project*, 2011.

Brand et al., *Freiburger Modellversuche zu neuen Stromtarifen*, 1990.

Brattle, *The Five Forces Shaping the Future of Demand Response (DR)*, presentation, February 2015

Bundesnetzagentur & Bundeskartellamt, *Monitoringbericht 2014*, 2014.

CEER, *Advice on Ensuring Market and Regulatory Arrangements help deliver Demand-Side Flexibility*, June 2014.

CEER, *Regulatory and Market Aspects of Demand-side Flexibility*, 2013.

CER, Electricity Smart Metering Customer Behaviour Trials (CBT) Findings Report", 2011.

CER/Utility Regulator, *Single Electricity Market: Demand Side Vision for 2020*, Consultation paper, August 2010

CLNR, Insight Report: *Domestic Time of Use Tariff – A comparison of the time of use tariff trial to the baseline domestic profile*, 2015.

Ecofys, *Einführung last-u zeitvariabler Tarife*, 2009.

Ecofys, *Waarde van Congestiemanagement*, 2016

EDF, Option Tempo., 2016.

Ene't GmbH, *Anzahl der Versorger mit Smart-Meter-Tarifen seit Januar verdoppelt*, 2011.

Enfo Energy and the Norwegian Smart Grid centre, *Position paper on the Aggregator role and barriers for utilizing demand side flexibility*, November 2014

EURELECTRIC, *Designing fair and equitable market rules for demand response aggregation*, March 2015.

EURELECTRIC, *Everything you always wanted to know about demand response*, 2015.

European Commission, Communication, *Delivering the internal electricity market and making the most of public intervention*. November 2013.

European Commission, *Report from the Commission: Benchmarking smart metering deployment in the EU-27 with a focus on electricity*, June 2014.

Eurostat, *Energy Balance Sheet*, 2015 edition.

Faruqui, Ahmad and Sergici, Sanem, *Arcturus: International Evidence on Dynamic Pricing*, 2013.

Faruqui, Ahmad, *Dynamic Pricing – The bridge to a smart energy future*, 2013.

Faruqui, Ahmad, *Price-enabled demand response*, 2014.

Fraunhofer ISI and Forschungsgesellschaft für Energiewirtschaft (2014) *Load Management as a Way of Covering Peak Demand in Southern Germany,* Agora Energiewende May 2014

Frontier Economics (2015) *Future potential for DSR in GB*, London October 2015

Gils, Hans Christian (2015) *Balancing of Intermittent Renewable Power Generation by Demand Response and Thermal Energy Storage*, Thesis for Doctor of Engineering Sciences Degree, University of Stuttgart, 2015

Gils, H.C. (2014) *Assessment of the theoretical demand response potential in Europ*e, Energy 67 (2014)

IEA, *Repowering Electricity Markets: Market Design and Regulation during the Energy Transition*, Presentation, July 2015

IEA, *Empowering customer choice in electricity markets*, 2011.

IEA DSM, Case Study – Winter Peak Demand Reduction Scheme. Found at: http://www.ieadsm.org/article/winter-peak-demand-reduction-scheme/

Jacapo Torriti, *Peak energy demand and demand side response*, 2015.

Kollmann, A. et al., *Lastverschiebung in Haushalt, Industrie, Gewerbe und kommunaler Infrastruktur – Potenzialanalyse für Smart Meter – Loadshifting*, 2013.

Low Carbon London, *Residential Demand side: Response for outage management and as an alternative to network reinforcement, Report A1*, 2014.

Mavir, *Data Publication*, 2016. Found at: https://www.mavir.hu/web/mavir-en/code-of-commerce

Ministerio de Industria, Energía y Turismo, Gobierno de España, *Planificación Estratégica: Plan de Desarrollo de la Red de Transporte de Energía Eléctrica 2015-2020*, 2014.

Pöyry, *Demand Side Response as a source for flexibility, 2015*

PWC, NSMP (Electricity & Gas (Cost Benefit Analysis), 2013.

Red Electrica de España, *Time-of Use tariff for small consumers in Spain*, 2016

Redpoint, *Electricity System Analysis – future system benefits from selected DSR scenarios*, 2012.

JRC, Bertoldi et al, *Demand Response status in EU Member States*, Draft report May 2016

Nord REG, *Discussion of different arrangements for aggregation of demand response in the Nordic Market*, February 2016

RAP, *Demand Response, Aggregation, and the Network Code for Electricity Balancing*, May 2015

Regulatory Assistance Project, *Demand response as a power system resource: program designs, performance and lessons learnt in the United States*, May 2013

SEDC, *Mapping Demand Response in Europe Today*, September 2015

Smart Energy Demand Coalition (SEDC), *Mapping demand response in Europe today*, September 2015

Smart Energy GB, *Is It Time? Consumers and Time of Use Tariff*, 2015.

Smart Grid Task Force/EG3 Report, *Regulatory Recommendations for the Deployment of Flexibility*, January 2015

Smart Region, *European Smart Metering Landscape Report 2012- updates May 2013*, 2013.

SWECO, *Study on the effective integration of Distributed Energy Resources for providing flexibility to the electricity system*, April 2015

Thema Consulting Group, *Demand Response in the Nordic electricity market. Input to strategy on demand flexibility*, 2014

UK Power Networks, *Residential Demand Side Response for outage management and as an alternative to network reinforcement*, 2014.

THEMA, *Demand response in the Nordic electricity market. Input to strategy on demand flexibility*. TemaNord 2014:553 2014, September 2014

THEMA, *Capacity adequacy in the Nordic electricity market.* TemaNord 2015:560, August 2015

University of Oxford, *Assessment of Demand Response Market Potential and Benefits for Shanghai*, July 2015

US Department of Energy, *Benefits of demand response in electricity markets and recommendations for achieving them*, February 2006

VDE-Studie (2012) *Demand Side Integration Lastverschiebungspotenziale in Deutschland*

Voss et al., , Lastoptimierung in elektrischen Netzen mit dynamischen Tarifen, 1991.

VVT, Aggregate Consumer's Flexibility in Consumption and Generation to Create "Active Demand", 2009.

Appendix B Studies on demand response potential

Studies of demand response potential

In a study of 30 different Swedish industrial consumers, Elforsk (2006) find that they may each reduce their consumption by 5 to 50 MW for a few hours during price peaks. The study reported a rather linear volume reduction in the price interval from 500 to 10 000 SEK/MWh (54 – 1072 EUR/ MWh). To unleash the full potential of 1 600 MW for all the 30 power intensive industries included in the study, the price peak needed to reach 13 000 SEK/MWh (1 393 EUR/ MWh).

According to Gaia (2011), a study by EME Analys estimated the potential for demand side flexibility in the Swedish industry as a whole to approximately 1 300 MW. To unleash the total potential, price peaks of 90 000 SEK/ MWh (9 646 EUR/ MWh) is needed for about 10 hours per year. Hence, the results from these two studies of Swedish industry DR differ both in terms of volume and price levels. It should be noted that for industry, product market prices are likely to affect the alternative cost of demand response if it implies a reduction in the industry output.

In the residential sector, demand response is most relevant for households with electrical heating. The share of electrically heated homes varies substantially between the countries. According to Gaia (2011), electrically heated homes in the Nordic countries each has a potential of switching 1-2 kW from peak hours to off-peak hours. This implies a total estimate of 4000-7000 MW flexible demand from households is based on the share of electrically heated homes and the estimated volumes per house. Approximately 6 per cent of Danish, 80 per cent of Norwegian and 50 per cent of Swedish households are currently electrically heated (Gaia, 2011). In Finland, where also a large share of households are electrically heated, the flexibility is to a large extent already utilized (i.e. demand shifted from day to night). The Gaia study, as well as other studies examined, does not describe the cost side for demand response from households. Another study of Swedish households, Sweco (2013), shows that single homes account for 70 per cent of all electricity used for heating (included heating of tap water) in Sweden. Electrically heated houses represent a potential to reduce 4-5 kW each in the period 8-10 in the morning (representing the peak load for the household, the potential will be lower outside of this hours), even with outdoor temperatures at 10-15 degrees below, without loss of comfort. The total potential for demand reductions for these households is estimated to 1500 MW (Sweco, 2013). The households' savings are estimated based on historical price variations in 2010 and 2011. The actual cost of realising this demand response is not estimated. However, a Swedish study shows that consumers are willing to reduce loads if they are informed of hours with high electricity prices. When consumers were informed by SMS or email, household consumption was reduced by 50 per cent in high price hours (Sweco, 2013).

Potentials and some costs of DR in energy markets and reserve markets

The price of DR can differ substantially between markets, and depends on both the need for flexibility, the alternative sources of flexibility, and the structure of demand. The table below shows the estimated current prices of the capacity mechanisms in the Nordic region. The current prices in the strategic reserves of Sweden and Finland reflect the costs of extending the lifetime of existing old plants used for reserves, and, in Sweden, even the cost of demand response in the reserve. Norwegian prices are relatively low due to the abundance of flexible hydropower resources in the Norwegian market.

Table 7.1: Historic prices for strategic reserves.

	Swedish strategic reserve 2014/2015	**Finnish strategic reserve 2014**	**RKOM Norway 2013/2014**
Estimated price [EUR/MW/year]	7 600	21 280	3 000 – 4 000

Sources: SvK, Fingrid and Statnett.

The evidence suggests that by designing more DR-compatible products, much more demand response resources can be activated in the market. However, the potential in processing industry will naturally differ between countries according to the industry structure.

The figures from the US market suggest that both DR participants in the wholesale market (mainly large power-intensive industry) and aggregated loads from smaller industry and commercial loads may participate in Capacity mechanisms. When it comes to aggregation of smaller industry and commercial loads, there is thus far little evidence to base estimates of potentials on, as we have seen in chapter 3. The experience from the US (PJM) does however offer some insights. A clear pattern emerges from the figures shown in Figure 2-9:

- *Interruptible loads* are mainly provided by C/I customers
- *Direct load control* is mainly provided by residential customers, presumably via aggregators
- *Emergency demand response* is mainly provided by customers participating in wholesale markets (directly)
- *Demand bidding and buy-back* is offered by C/I customers, presumably via aggregators, and wholesale participants
- *Reserves* are exclusively offered by wholesale participants

The first three categories, in addition to capacity reserves, are the largest ones.

It is not clear from the figure in what time-frames these resources are activated. For example, interruptible loads may be used in order to balance supply and demand in the market (in the DAM, or in real-time), but more often, these resources are used to manage congestions in distribution or transmission grids. For example, some DSOs in Norway offer (long-term) interruptible (grid) tariffs in order to reduce the need to invest in grid capacity. The largest grid company in Norway, Hafslund, reports to have saved significant investments due to interruptible contracts. They also report that the contracts have been achieved by targeted efforts towards relevant customers. The customers on interruptible contracts are typically small industries or CHP with heat pumps. The interruptible contracts may also be used by the TSO, and sometimes the TSO orders distribution grid companies to provide interruptible contracts for services to the TSO. Statnett currently has 400-700 MW of capacity available as interruptible loads.

Reduced grid tariffs for interruptible loads are also offered in Finland.

There is presumably a large potential for demand response in power intensive industry, e.g. in Sweden and Finland. On the other hand, large industry is already active in reserve markets and is to some extent providing price sensitive bids in the spot market. The questions are therefore if there are additional volumes that may be activated in the case of capacity shortage – and what it takes to provide such response.

Estimates of potentials and costs in the Nordic area

Industry

Dansk Energi Analyse (2010) conducted a project during 2006-2010, which aimed to increase the Danish industry's interest to engage in the different electricity markets. The study showed that price levels both in the spot market and the reserve market during this period made these markets unattractive for the industry players. If the payment in the reserve market were less than 200 000 DKK (27 000 EUR) per MW per year, the companies in the project would not find it interesting to participate in the market. If the level increased to 400 000-600 000 DKK (54 000 - 80 000 EUR) per MW per year, the interest would however be significant. The price level per activation will thus be lower the more frequently the volumes are activated.

Fingrid (2014) takes an optimistic view when it comes to activating more DR in Finland. They estimate that DR participation in reserve markets could increase from the current 100-500 MW to 500-1.000 MW by 2020 (peak load expected at 16.500 MW, i.e. DR is 3-6 percent of peak), including increased DR from smaller customers that are not very active today. According to Gaia (2011), there is a flexibility potential of 500 MW in Finnish industry, but the potential is rather uncertain as it is not clear if this is an additional potential to the flexibility currently utilized in the market.

An example from another Swedish study (Sweco, 2013), estimates the cost of implementing power control in the Swedish food industry to 500 000 SEK (53 600 EUR), of which equipment costs amount to 150-200 000 SEK (16 080 – 21 435 EUR). The technical cost of power control is not very high compared to prices in the reserve markets, but may still be considered as an investment risk if the income potential is not easy to predict.

Large buildings

According to EA Energianalyse (2011), 50 per cent of the electricity used for cooling and freezing processes in Danish production companies might be flexible, while as much as 70 per cent of the electricity used for the same purposes in the trade and service sector might be flexible (supermarkets). Supermarkets are closed during nights and may use these hours for extra cooling, thereby reducing their demand for cooling during peak hours in the morning. Ventilation is the second largest contributor of demand flexibility for large electricity consumers. The study estimates that 15 per cent of the electricity used for ventilation in the trade and service sector might be flexible. Electricity used for ventilation in industrial companies is expected to have a larger potential for flexibility due to a less sensitive comfort level in this sector.

Demand flexibility in Sweden is summarized in Sweco (2013). The potential for load reduction with a duration of three hours from large buildings is estimated to 200 MW. Most of the potential comes from ventilation and cooling in office buildings. This potential is supposed to be easily available through re-programming of existing automation systems and could be realized at spot prices above 3 SEK/kWh (0.3 EUR/ kWh). Hence, this potential could be realized via real-time pricing, but probably requires contracts with energy service providers who may be aggregators in most markets.

Households

Broberg et.al. (2014) discuss the households' willingness to participate in different demand response schemes where some loads may be remotely controlled. The study estimates what level of compensation is needed for remote control of heating or general electric equipment at different times of day, and more generally in extreme situation. The study finds that the compensation needed to accept external control is lower for heating than for other appliances. Table 4.3 provides a summary of the results.

Table 7.2: Average necessary compensation for Swedish households to take part in demand response schemes

The suggested scheme for remote control of electricity consumption	**Yearly compensation compared to no remote control[127]**
Compared to no remote control of heating: *Demanded compensation for remote control in the morning (7.00-10.00)* *Demanded compensation for remote control in the afternoon (17.00-20.00)*	 No significant compensation 68 EUR
Compared to no control of electricity	89 EUR

[127] Numbers are converted from SEK using an exchange rate of 9.3 SEK per EUR.

consumption in general: *Demanded compensation for remote control in the morning (7.00-10.00)* *Demanded compensation for remote control in the afternoon (17.00-20.00)*	154 EUR
Compared to no remote control in extreme situations *Demanded compensation for remote control in extreme situations*	4.7 EUR per day
Demanded compensation to change todays contract.	295 EUR

Source: Broberg et.al. (2014)

Broberg et.al. (2014) notes that the results cannot be translated into a cost per kW demand response, as it is not the cost for a specific load reduction (EUR/MW), but the compensation needed for the household to be willing to participate in the scheme for load control. We do not know if loads are turned on when load reductions are needed or how often the loads may be disconnected. The study also indicates that consumers are more willing to take part in demand response schemes at times when they are not at home, i.e., when they are not directly affected by the (potential) load reductions.

This study indicates that households may want high compensation to allow for dispatch in incentive based DR.

Service provision based on home automation

Service providers may bring additional volumes of flexibility to the market when they improve margins though economies of scale (limiting costs) and better optimization of flexibility (enhancing revenues). The cost of service providers is shared among the customers and will normally include:

› *Technology*. Investment and implementation of equipment for exchange of information, optimization and execution of load changes (included in-house communication). Energy management systems and automation are relevant both to improve energy efficiency and to enable demand response.

› *Competence*. Competence on e.g. power markets, market operation, trading, risk management, regulatory issues and new technology.

› *Administration*. Costs of performing the services provided to the customer

New technology and services to help customers save electricity are being offered to Nordic consumers. Most products control consumption based on expected energy demand (due to weather forecasts) and prices (spot price and/or time-of-use grid tariffs). The Finnish energy companies, Fortum and Helsinki Energia, have e.g.

introduced products that optimize electricity used for heating water in heat storage tanks used for space heating in single homes. The products are still new (introduced in 2014) and the market penetration is yet limited.

The Norwegian utility, Lyse Energi, has developed a similar product called Smartly. Smartly includes automatic control of heating, lighting, intruder and fire alarms. This product will be offered to customers as hourly metering is rolled out in Lyses grid area, but still only a limited share of consumers have smart meters.

The service provider Ngenic has developed a cloud-based heating control system for Swedish households. The technology intends to optimize the customer's comfort and energy use based on sensor data, weather forecast, building dynamics, energy prices, grid load and behavioural patterns.

Table 54 lists some products offered in the Nordic market and their prices.

Table 3: Costs of some demand response services focusing on small consumers

Country	Service provider	Product	Instalment cost	Fixed monthly cost
Finland	Helsingin Energia	Termo home automatation	600 Euros	6 Euros
Finland	Fortum	Fortum Fiksu	124 Euros	15 Euros (first three years) 4,95 Euros (succeeding years)
Norway	Lyse Energi	Smartly heating control	850 Euros*	4,75 Euros
Norway	Lyse Energi	Smartly light control	1000 Euros*	3,50
Sweden	Ngenic	Ngenic tune	550 Euros 333 Euros	0 5,50 Euros

*investment support may cover up to 35 percent of the instalment costs

Appendix C Consulted stakeholders

In order to clarify and validate the assessment specific targeted interviews were made.

The following organisations have been interviewed in person or by phone.

- ENTSO-E (Marco Foresti, Market Design Senior Advisor)
- Tennet (Erik van der Hoofd, Market Design Developer
- Voltalis (Pierre Bivas, CEO)
- Smart Energy Demand C (Jessica Strombeck, Chairman)
- Regulatory Assistance Project (Michael Hogan, Senior Advisor)
- PA Consulting expert working for OFGEM

The key findings are presented below. This short summary includes the interviewees' comments, opinions and statements. It addresses the following issues:- (i) the current situation regarding demand response, (ii) the barriers for increased demand response and specifically (iii) the issue of compensation in case of independent demand aggregators.

Regarding incentive based demand response in general:

- Though some Member States have more experience, the European market for demand response is only still in its nascent stage.
- At present, incentive-based demand response comes from large customers and through reserve-based products.
- It has been stated that only the day ahead market is liquid enough to provide a reference price.
- In many cases, participants' sales did not go through the physical markets. It was estimated that it could be only 20% of the demand and supply of electricity that went through the physical markets). This may mean that a supplier/BRP could be almost fully contracted ahead of the physical markets and hence they may not benefit from lower spot prices.
- The total market (e.g. realistically achievable) potential for demand response was estimated to be of the order of 50GW in Europe.
- There are many reasons for the slow uptake of demand response. These include:
  - It has been stated that generator-supply firms risk losing market revenue and share from demand aggregation (independent or otherwise) and are reluctant to engage
  - Regarding the large generation-supply firms, it was stated by certain respondees that they are revenue/ market-share rather than profit driven and hence they see demand aggregation as a threat to this. Another view given was that these companies, which have traditionally been driven by investments in physical assets, are not ready to push forward IT-based solutions.
  - It was suggested on several occasions that there is currently excess generation capacity in Europe, which in turn reduces the incentive to engage in demand response.
- Concerning comments on the question of the activation and opportunity costs of consumers, it was suggested that these costs often lower than expected and can go as low as €50/70/MWh for domestic customers. For example, for residential and SMEs consumers, switching off heating might not be noticed by the consumer and therefore this kind of demand response could be offered maybe for 15% of all hours during the heating season (e.g. high use periods during the 4/5 winter months, or approximately 1000 hours per year). For large consumers (industry), while activation costs may

also be low, the opportunity costs can be considerably higher and they might therefore only be activated during the top 30 high price high usage hours.

Incentive based demand response and the compensation issue:

- There were very different viewpoints on the effects of compensation.
- One the one hand it was claimed that without compensation there would not be a business case for incentive-based demand response in the form of demand aggregation.
- In this vein, it was also suggested that depending on the specific compensation rules, compensation could reduce or eliminate the presence of independent demand aggregators. For example, compensation could mean that only the largest consumers are interesting for demand aggregators.
- On the other hand, other respondees stated that excluding aggregators from balance responsibilities (e.g. the situation without compensation) would lead to inefficient markets given that balance responsibility is a core element of the EU Target Model. One commentator noted that independent aggregation without compensation would disrupt the market by over-encouraging inefficient demand response. According to these respondees, to avoid such inefficiencies, demand aggregators need to compensate BRPs or become BRPs themselves.
- Some took a middle of the road position claiming that an aggregator could still make money if there was a difference between the wholesale market price and the 'compensation price'.

Appendix D Demand functions

Demand function are included in separate Excel file. The format is as illustrated here. There table shows each consumption category and there is similar set of data for each Member State.

Consumption type	**Consumption class**	**Consumer type**	**DR potential 2016 (MW)**	**DR potential 2020 (MW)**	**DR potential 2030 (MW)**	**Cost of activation (€/MWh)**	**Max. shift duration (h)**
Aluminium	Process Technology	Industrial	0.000	0.000	0.000	225	12
Copper	Process Technology	Industrial	0.040	0.080	0.157	225	12
Zinc	Process Technology	Industrial	0.000	0.000	0.000	225	12
Chlorine	Process Technology	Industrial	0.392	0.770	1.443	225	6
Mechanical Pulp	Process Technology	Industrial	3.780	7.528	14.801	225	3
Paper Machines	Process Technology	Industrial	2.878	6.147	13.350	225	3
Paper Recycling	Process Technology	Industrial	3.103	7.044	16.480	225	3
Electric Steel	Process Technology	Industrial	3.044	6.696	16.658	225	12
Cement	Process Technology	Industrial	3.134	6.170	11.831	225	6
Calcium Carbide	Process Technology	Industrial	0.125	0.238	0.422	225	6
Air Separation	Process Technology	Industrial	0.229	0.465	0.957	225	6
Industrial Cooling	Air conditioning	Industrial	1.564	3.156	6.363	70	1
Industrial Building Ventilation	Ventilation	Industrial	0.829	1.673	3.373	70	1
Cooling Retail	Cooling	Commercial	5.257	11.528	25.764	70	1
Cold storage houses	Cooling	Commercial	0.701	1.537	3.435	70	1
Cooling Hotels/Restaurants	Cooling	Commercial	1.051	2.306	5.153	70	1
Ventilation Commercial Buildings	Ventilation	Commercial	9.951	21.451	46.283	70	1
AC Commercial Buildings	Air conditioning	Commercial	0.844	1.900	4.520	70	1

Consumption type	**Consumption class**	**Consumer type**	**DR potential 2016 (MW)**	**DR potential 2020 (MW)**	**DR potential 2030 (MW)**	**Cost of activation (€/MWh)**	**Max. shift duration (h)**
Storage hot water commercial sector	Thermal energy storage	Commercial	1.277	2.888	6.509	55	12
Electric storage heater commercial sector	Thermal energy storage	Commercial	0.000	0.000	0.000	55	12
Pumps in water supply	Process Technology	Commercial	2.359	5.112	10.908	225	6
Waste water treatment	Process Technology	Commercial	0.472	1.023	2.182	225	6
Residential refrigerators/freezers	Cooling	Residential	13.112	26.852	41.696	70	1
Washing machines	Laundry	Residential	4.302	8.968	14.643	10	24
Laundry driers	Drying	Residential	2.496	5.744	11.860	10	24
Dish washers	Washer	Residential	4.076	8.722	15.824	10	24
Residential AC	Air conditioning	Residential	0.198	0.648	2.266	70	1
Storage hot water residential sector	Thermal energy storage	Residential	4.060	9.194	18.031	55	12
Electric storage heater residential sector	Thermal energy storage	Residential	9.913	21.418	35.799	55	12
Residential heat circulation pumps	Heating	Residential	6.764	15.127	27.228	10	12
Electric vehicles/batteries	Batteries	Residential	14.943	70.952	499.193	10	3
Heat pumps	Batteries	Residential	2.884	11.203	49.919	10	3