Time-based pricing and electricity demand response: Existing barriers and next steps

Cherrelle Eid [a], [*], Elta Koliou [a], Mercedes Valles [b], Javier Reneses [b], Rudi Hakvoort [a]

[a] Delft University of Technology, P.O. Box 5015, 2600 GA, Delft, The Netherlands
[b] Instituto de Investigación Tecnológica, Universidad Pontificia Comillas, c/Alberto Aguilera 23, 28015 Madrid, Spain

A B S T R A C T

Interest in Demand Response (DR) is increasing due to its potential to improve reliability and save costs for electricity systems. DR can provide a sustainable and cost-effective option for supply balancing, especially in a scenario with more volatile inflows from renewable energy sources. End-users can be incentivized to provide DR through time-based pricing in general and dynamic pricing in particular. This paper provides a theoretic framework and practice-oriented review of the status of DR in Europe, outlining the major challenges currently hampering further DR development. Important challenges involve the split-incentive issue for investments in enabling technologies, traditional market rules for flexibility that favor large generation units and the need for electricity market and network operation coordination.

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1. Introduction

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

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

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

The value and necessity of DR is recognized by the European Commission (European Commission, 2013a). The Energy Efficiency Directive (EED), Art.15, explicitly urges EU national regulatory authorities to encourage demand-side resources, including DR, "to participate alongside supply in wholesale and retail markets", and also to provide balancing and ancillary services to network operators in a non-discriminatory manner (Directive 2012/27/EU)

* Corresponding author.
  E-mail addresses: C.Eid@tudelft.nl (C. Eid), E.Koliou@tudelft.nl (E. Koliou), Mercedes.Valles@iit.upcomillas.es (M. Valles), Javier.Reneses@iit.upcomillas.es (J. Reneses), R.A.Hakvoort@tudelft.nl (R. Hakvoort).

(European Commission, 2012a). Furthermore, main European Policies advocating for DR to participate alongside supply in wholesale markets calling for aggregation are the Directives 2009/72/EC regarding common rules for the internal market in electricity, the ENTSO-E 2013 Demand Connection Code, and the ACER 2012 Framework Guidelines on Electricity Balancing. Hence, mechanisms for implementing DR are receiving increasing attention by European regulatory authorities and institutions (CEER, 2011). DR potential in the EU electricity markets is believed to be high but currently underutilized (European Commission, 2013b), especially for residential consumers, on account of current institutional arrangements that cater to large generators and industrial customers.

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

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

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

The paper is structured as follows. Section 2 provides a theoretical description of DR and Section 3 presents the necessary elements of electricity billing for incentivizing DR. Next, Section 4 presents examples of time-based prices for demand response in Europe. Lastly, Section 5 outlines major barriers for DR activation followed by conclusions and policy recommendations in Section 6.

2. Definition of demand response

The literature provides various definitions of demand response, but a clear common theme is that DR reflects electricity demand that is intentionally responsive (flexible) to economic signals (see Table 1 for frequently cited DR definitions in the literature and policy documents). An important difference between demand response and demand-side management is that demand side management (DSM) can be seen as the over-arching concept that can encompass demand response (in addition to energy efficiency and electricity storage), driven by DSM adapters and policies (Warren, 2014).

In the US, as of 2014, DR programs alone were estimated to have a potential of 28,934 MW consequently accounting for 6.2% of the total peak demand (FERC, 2015). Within Europe, there are long standing arrangements or programs to involve energy-intensive industrial customers in DR (mostly through interruptible tariffs or time-of-use pricing), and some system operators make use of large avoided loads as part of their system balancing activities (Torriti et al., 2010). Countries with large penetration of RES, such as Germany, currently use demand flexibility to maintain system-wide reliability (Koliou et al., 2014).

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

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

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

2.1. Types of DR and effects on the electricity system

Demand-side management programs could be aimed toward modifying traditional electricity demand in different ways (see Table 2 for a visual presentation of the types of adjusted load shapes). Demand response that is aimed at decreasing consumption during peak times can be categorized as peak clipping. Load shifting is mostly associated with usage reduction at peak that is offset by usage in off-peak hours. DR that is aimed at increasing consumption levels (for example at times with high renewable energy production) can be categorized as valley filling, load building, or flexible load.

2.1.1. Benefits of demand response to the electricity system

The potential benefits of DR rest upon the energy policy pillars associated with economic, environmental, and reliability objectives (see Aghaei and Alizadeh, 2013). Economic or market-driven DR reduces the general cost of energy supply while preserving adequate reserve margins and mitigating price volatility by means of short-term responses to electricity market conditions. Environmental-driven DR would serve environmental and social purposes by decreasing energy usage, increasing energy efficiency, defining commitment to environmentally friendly generation, and reducing greenhouse gas emissions. Lastly, network-driven DR aims to maintain system reliability by decreasing demand in a short period of time and reducing the need to enhance generation or transmission capacity.
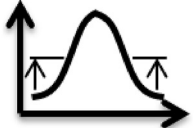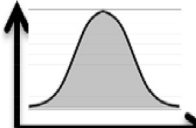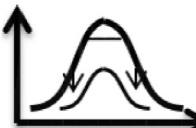
Battle and Rodilla classify DR benefits in accordance with time. For the short and medium terms, DR would decrease network peak and risk of system collapse by keeping electricity flows within technical constraints. In the long term, DR could decrease generation and network investment needs, relieve regular congestion, and increase energy efficiency (Batlle and Rodilla, 2009).

In this work we define additional DR benefits from a technical system perspective based on alignment with time-based pricing. Hakvoort and Koliou (2014) describe DR objectives associated with day-ahead optimization, hour-ahead optimization, network peak reduction, local balancing, real-time control, DG optimization and central RES optimization. Secondary forthcoming effects include CO_2 reduction and decreased need for distribution and transmission network investments. As discussed in Section 4, smaller,

Table 1
Frequently cited demand response definitions (Koliou, 2016).

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

Table 2
Adjusted load shapes as a result of DSM (Chuang and Gellings, 2008; Gellings, 1985; Hakvoort and Koliou, 2014).

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

residential demand flexibility must be aggregated before in order to be eligible for trade in central markets (such as balancing markets). The aggregation function can be provided by an independent aggregator, an electricity retailer, or even the network operator.

2.2. Activation of demand response

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

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

Price-based DR refers to "changes in electric usage by end-use customers from normal consumption patterns in response to changes in the price of electricity over time" (DOE, 2006). The theory of price-based DR for large industrial electricity users was discussed by David and Lee (1989). Pricing options include real-time pricing (RTP), critical-peak pricing (CPP), time-of-use pricing (TOU), and peak-time rebates (PTR) (Newsham and Bowker, 2010; see Table 3). Drivers for such rates could be high wholesale market prices or factors that jeopardize system reliability (Koliou et al., 2013).

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

Depending on the electricity market design, a distribution system operator (DSO), aggregator, retailer, and/or a third party could provide separate price signals to the end user. With smart grids, ex-ante tariffs can incorporate dynamic prices based on real-time

Table 3
Possible time-based pricing options for DER management (David and Lee, 1989; Faruqui and Sergici, 2009; Hakvoort and Koliou, 2014).

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

electricity supply and network conditions. Due to the fact that there are minimum trading values for the balancing and other free markets, small users must be bundled or aggregated to simultaneously provide significant tradable amounts of flexibility in those markets (see Section 4). Aggregation and load bundling can occur per load type, e.g. EVs can be represented by one entity and home battery systems by another.

3. Time-based tariffs within the billing context

Electricity pricing is an important method by which end-user demand response can be incentivized while maintaining voluntary choice. The final electricity bill depends on the respective cost-components and other (policy) objectives associated with the charges allowed under the tariff. This section sequentially describes cost allocation (Section 3.1), customer charging (Section 3.2), and demand response aspects within this context (Section 3.3).

3.1. Cost allocation

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

Traditionally, electricity systems were operated by large vertically integrated electricity utilities (combining electricity generation and transport) to with their own electricity billing structures and tariff levels. This model still prevails in many US states and other countries, where electricity is billed by a central public service utility whose regulated tariffs could reflect combined network and electricity supply costs incurred to the final user. Alternatively,
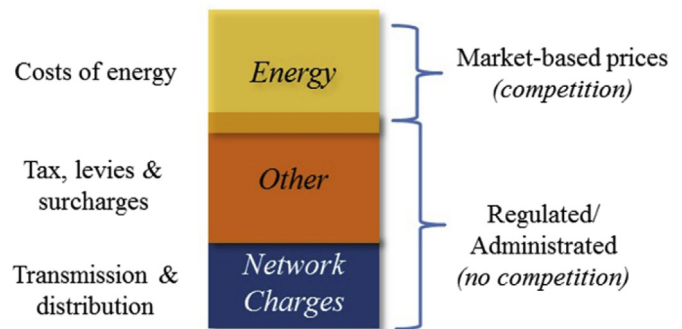

Fig. 1. Usual breakdown of electricity retail rates in a competitive environment (Eurelectric, 2013).

in a liberalized electricity sector, the monopolistic components of the electricity value chain (the electricity transport network) are unbundled from the competitive parts (e.g. generation and retail). The general composition of the cost allocation elements in the liberalized electricity market model (mainly prevailing in Europe) is presented in Fig. 1.

3.1.1. Electricity production

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

However, enabled by smart-grid technologies, increasing levels of demand are now served by stochastic supply from renewable resources and distributed generation. This electricity is not only fed to the high-voltage grids, but also to the low-voltage grids through

"prosumption" (Pérez-Arriaga et al., 2013).[1] Consequently, in future electricity systems the *generation-follows-demand* perspective is increasingly replaced by a *demand-follows-generation* perspective. This transition requires that electricity consumers receive real-time reflective information regarding the electricity prices through dynamic pricing (Pérez-Arriaga et al., 2013).

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

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

3.1.2. Cost for electricity transport

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

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

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

measures.

3.1.3. Other costs

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

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

3.2. Charging the customer

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

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

3.2.1. Traditional electricity billing

Typical billing components on electricity bills are the energy charge (€/kWh), a capacity charge (€/kW), an access charge (a one-time payment), and the customer charge (a yearly or monthly payment). Traditional electricity charging does not further categorize between consumers and prosumers with uniform rate structures. However, in a smart-grid environment where demand participation is fostered, end-user tariffs can incorporate customer categorization, time and location (Picciariello et al., 2015). See Table 4 for some examples.

The application of dynamic prices is different for vertically integrated utilities providing a single (integral) tariff as compared to regulated and private service providers in a liberalized market. The electricity tariff could therefore be divided in the nature of the costs (distribution or retail prices) and these prices could be flat or time-dependent. Otherwise the arrangements could be set for an independent aggregator. The final tariff could reflect full-dynamic prices, semi-dynamic prices, or another pricing arrangements with for example a new actor like an aggregator. If the full dynamic price comprises of an integral tariff in which a single price incorporates both retail and distribution costs. Alternatively, a full dynamic price could be set up by two different prices for both retail and

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[1] Prosumption refers to the presence of electricity customers that are able to both consume and produce electricity based on DG ownership, grid connection, and a method of compensation.

Table 4
Tariff components and options for tariff design (Eid et al., 2013).

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

distribution. Within a semi-dynamic price, one part of the price for electricity is can be fixed price, for example like the customer charge in the United States. Other arrangements could be that an aggregator sets up a specific contract for demand response (See Fig. 2).

3.2.2. Pricing to promote demand response

For some methods of electricity pricing, including pricing for flexible and reliable demand response, the installation of technical devices is required. For example, with peak-time rebates the baseline consumption level of the customer is needed in order to rebate for the supplied DR. With direct control methods, in-home automation is needed that communicates with the signal from the aggregator for example (or other actor that contracts the flexibility of the end-user). Table 5 provides some examples of tariff options and required smart-metering and home adjustments for the customer to be able to supply the DR Service.

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

generation costs during the day. Alternatively, transient signals can be used to reflect variations in distribution costs. Thus, if a zone is congested during only some hours of the year, non-permanent punctual signals such as CPP can be used in that zone.

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

4. Examples of demand response projects

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

4.1. Industrial demand response

The advantage of having large industrial consumers provide demand response is that their change in consumption patterns significantly affects the electricity system as a whole. Specifically, industry accounts for more than one third of total electricity
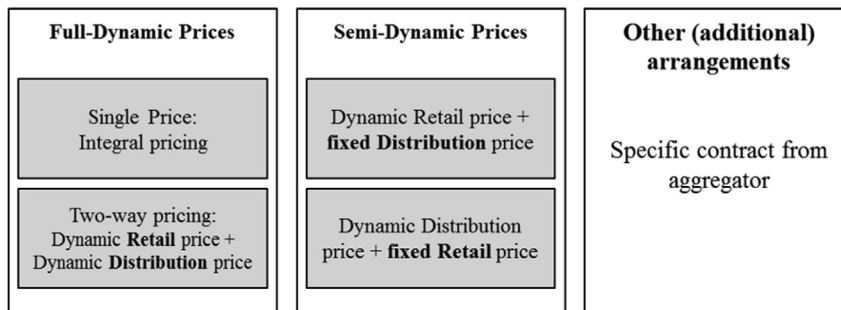

Fig. 2. Different billing methods to incentivize demand response.

Table 5
Tools required for demand response activation.

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

consumption in Europe, which in turn brings confidence to the predictability of load patterns (EEA, 2012). Aggregation is cost effective and reliable in large volumes due to the tradability of their load flexibility on balancing and reserve markets. In addition to aggregation, large industrial users could also be subject to timed-based or dynamic-pricing from their supplier or TSO in order to incentivize demand response. Below we discuss examples of industrial DR that provide insight into the role of aggregation.

4.1.1. France: Energy Pool

In France, Energy Pool is an aggregator that started operation in 2008. Its clients are mainly large industries (data centers, hospitals, residential and tertiary buildings, refrigerated warehouses, water cleaning and treatment facilities, and electric vehicles) that are geographically spread across the country. DR consists of around 1000 MW flexible capacity in the form of load reduction. Energy Pool takes charge of optimal decision-making for the industrial user's DR: it identifies flexibility potential, integrates the DR into the normal business processes of its clients, and offers the flexibility in different markets. These markets are the balancing markets (day-ahead and intraday), security reserve markets (long-term contracts and emergency operations), and capacity markets (mid-term or long-term contracts). Energy Pool clients receive specific payments for their participation in load management programs. Energy Pool now operates besides in France also in the UK and Belgium and has contracts with the TSOs in those countries.[2] (Energy Pool, 2015).

4.1.2. United Kingdom: flextricity

Flextricity is an industrial DR aggregator that started operation in 2004 in the United Kingdom. Flextricity provides both generation and load aggregation, meaning that it can incentivize clients for upward and downward load management and eventually trade this flexibility in markets. Flextricity's clients are large industrial and commercial customers (more than 500 kW) and owners of small hydro and stand-by generators.[3]

Usually there is no cost at all for the consumers to participate in Flexitricity's aggregation programs, as the company itself installs the communication, metering, and control equipment. The flexibility is supplied to short-term operating reserve (STOR) (generators), which is a service for the provision of additional active power from generation or demand reduction if power fails or demand is higher than expected. Furthermore, DR is used for triad management (comparable with critical peak), which is carefully targeted generation and demand reduction to optimize revenues for the involved businesses in contingency situations. Lastly, this DR is provided for frontline generation and load adjustment on short notice (below 10 s for 750 kW or more).

Furthermore in the industrial and large commercial sectors, energy-intensive users are able to enter TOU or interruptible contracts with suppliers. Similarly, the transmission system operator

can contract such large users directly as part of their network balancing activities (Torriti et al., 2010).

4.2. Residential demand response

4.2.1. France: direct load control and Tempo Tariff

An example of rigorous DR is direct load control (DLC) of the customer load by a central actor. Direct load control is mostly applied when the system is in a contingency situation and usually leaves no freedom for the user. An example is provided by the aggregator Voltalis in Brittany, France.[4] Customers contracted with Voltalis receive a free device installed in their home, named Blue-pod, which reduces heating operations in short time intervals when Voltalis receives a signal from the TSO based on endangered electricity supply sufficiency. In this DR program, customers are automatically enrolled, but can opt-out at any time by pushing a button on the device and using their heater as usual. Users do not receive an additional financial benefit, but observe a reduction of their normal electricity bill (usually 5–10%) due to the interruptions. The advantage of this type of DR is that it requires no additional tariff settlement, and therefore is easy to implement.

In France, a combination of CPP and TOU pricing is also applicable for customers that apply for the Tempo Tariff. Electricité de France (EDF), had in 2010 around 350,000 residential customers and more than 100,000 small business customers using the Tempo tariff. Within this tariff scheme, days are distinguished according to price using a color system, together with an indication of whether the hour is currently one of eight off-peak hours. Customers can adjust their consumption either manually or by selecting a program for automatic connection and disconnection of separate water and space-heating circuits. It has been estimated that for the average 1 kW French house, the Tempo tariff brought about a reduction in consumption of 15% on "white" days and 45% on "red" days. On average, customers have saved 10% on their electricity bill (Torriti et al., 2010), which can be significant especially considering harsh winters the reliance of a majority of French households on electric heating.

4.2.2. Sweden: DR for network congestions

Sweden is one of the few countries in Europe with 100% smart meter roll-out (Eurelectric, 2013). A portion of the customers from DSO Sala Heby Energi Elnät AB, the electricity distribution area that covers the provincial country town Sala and its environs, receive a TOU price for electricity distribution service.

Prior to the introduction of the demand-based time-of-use electricity distribution tariff (henceforth referred to as the demand-based tariff), all households in the local electricity.distribution area of the utility were charged according to a conventional distribution tariff composed of an annual fixed access charge (SEK/yr.), the rate of which was dependent on fuse size, and a variable distribution

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[2] See the website of Energy Pool: http://www.energy-pool.eu/.
[3] See the website of Flextricity: https://www.flexitricity.com/.
[4] See the website of Voltalis: http://www.voltalis.com/.

charge (SEK/kWh). Alternatively, the demand-based tariff consists of the fixed access charge (SEK/yr.) and a variable distribution charge (SEK/kW) that is calculated based on the average of the five highest hourly meter readings during peak hours. In off-peak hours, electricity distribution is free of charge.

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

4.2.3. The Netherlands: DR pilot for electricity transport and supply

In the Netherlands, the DSO Enexis has formed a consortium with an energy retailer (Greenchoice) and a project developer (Heja) to conduct a pilot in an apartment block and a group of semi-detached houses in Breda. This project tested dynamic retail, distribution, and local production pricing for household consumers. The retail tariff is based on the day-ahead price variation that is multiplied by a factor in order to make the average price equal to one if the traditional fixed kWh price for electricity from the supplier would be charged (this fixed price was around 0.2193 €/kWh during the pilot). This results in a retail price fluctuating between 0.06 €/kWh and 0.36 €/kWh each day (see Fig. 3).

The transport tariff is a dynamic peak-pricing scheme, which is dependent on the daily peak-hours and not solely critical peak hours at event days within a year. The peak pricing scheme for transport applied to consumption taking place above 80% of the consumption load during the daily peak. During days with a high morning peak (such as weekend days), these hours are also charged the peak price (see Fig. 4) (Kohlmann et al., 2011).

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

In the Netherlands (and most other European countries), the DSO is a natural monopoly that should provide non-discriminatory third-party access; it is not allowed to hamper or affect market activities for retailers or other market parties due to the possibility of price discrimination. Dynamic tariffs that vary in both time and place might discriminate customers by increasing price in a geographic area specifically with capacity problems, and not in
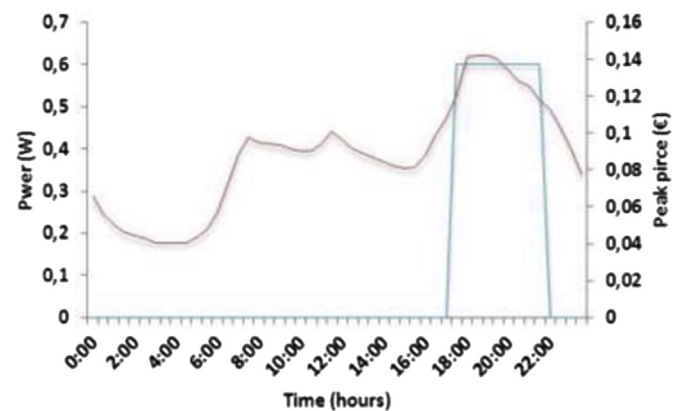

Fig. 4. Dynamic transport tariff on week day with load curve in Watt and the transport tariff in € (Kohlmann et al., 2011).

neighboring areas without capacity problems (Lunde et al., 2015). Therefore legal considerations may limit general application of the tariff settlement used in this pilot project.

5. Challenges for development of DR in Europe

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

5.1. Initial technology investments

The installation of smart meters, in-home displays, and other devices for enabling DR is costly. For example, the installation cost of a smart meter in Europe is on average between € 200–250.[5] An important question is who initiates the installation of smart meters—the consumer, the retailer, the aggregator, or the DSO? This common *split incentives* problem is related to the fact that the costs and benefits from flexible demand should be split between the end-user and the enabling actor, in view of creating a viable business case for both (Hakvoort and Koliou, 2014).

For example, if the electricity retailer invests in the smart meter, and the customer wants to change suppliers, this investment by the settled retailer is essentially foregone. If the DSO makes the investment, this constitutes a competitive advantage compared to the retailer because the DSO can use prices to alter consumption for network purposes. Without any clear business model for investments, no actor will make the first move. It is important that those benefiting from DR, directly or indirectly, pay for the costs (Energy Pool, 2015). Consequently, the value of DR should be distributed along the electricity supply chain, together with incentives for participation for each agent under clearly elaborated business models (Hancher et al., 2013). Therefore, taking into account that environmental benefits of DR are socialized, the cost also could be settled in a socialized manner. And just as it is the case in many markets with priority access for renewables, priority access for demand response in markets could further support its developments (Koliou et al., 2014).
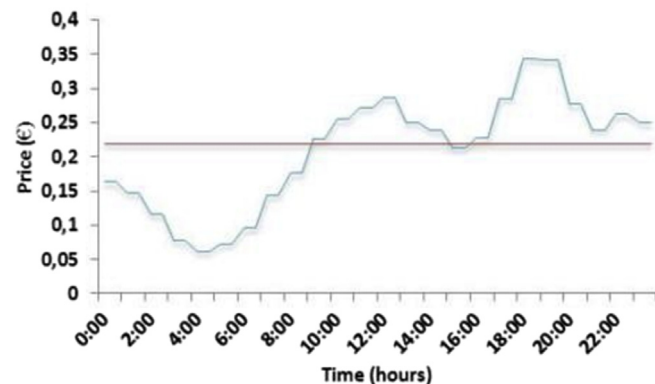

Fig. 3. Dynamic retail price with the straight line providing the standard electricity price as charged by the electricity supplier (Kohlmann et al., 2011).

5.2. Coordination problems

The *coordination problem* is another issue associated with DR deployment (Hakvoort and Koliou, 2014). At a certain points in time, some actors involved in electricity supply could require the demand to be adjusted downward, while others could actually require upward demand adjustments. This is especially the case in liberalized electricity sectors, where the network and supply functions are unbundled from each other. In Germany, for example, oversupply of wind electricity can result in *low* supply costs, while simultaneous network capacity limits can result in *high* transmission costs. Therefore, trying to incorporate multiple purposes over a time horizon with competing effects is impractical and may lead to unclear economic incentives. How customers respond depends on their price elasticity relative to the particular load modification. Therefore, the assessment of the exact load modification, its time horizon, and the price elasticity for such response must be taken into account. The coordination issue requires that tariffs ex-ante manage interactions for specific moments in time when opposing signals appear. Furthermore it requires reconsideration of regulation in liberalized electricity markets where the DSO is not allowed to hamper market activity with network tariffs due to non-discriminatory third-party access rules.

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

5.3. Incumbent issues: flexibility and traditional markets

In Europe, the need for demand flexibility from the residential sector is not critical in many places due to sufficient capacity within the distribution grid and flexibility provision from industrial consumers. However, in the next 15–20 years, when RES are expected to provide a significant part of the electricity production (based on the very ambitious European target of 100% RES in 2050), activating residential flexibility will become increasingly important. As discussed already by Koliou et al. (2014), the rules for balancing, ancillary, and real-time trading should be adjusted to accommodate aggregated load flexibility. If aggregators are hampered to provide flexibility services, the transition toward a renewable based electricity system becomes a greater challenge. Traditional peaking units in many RES based systems, however, already cope with recovering stranded costs and would be further affected by DR that shifts income to aggregators.

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

5.4. Non-sustainable side-effects of DR: shifting peaks and increasing emissions

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

As described in Section 2.1.1, there are energy-mix dependent consequences of load shifting from peak to off-peak periods. The economic effects of consuming electricity from cheaper production (like coal), might lead to less operation of more expensive units (such as gas fired plans). Depending on the current merit order, sometimes load shifting might induce higher CO_2 emissions as a result of increasing base-load production that is then met by coal-fired units, while reducing peak-load generation that could be met by cleaner, gas-fired units (Conchado et al., 2011; Holland and Mansur, 2008). However, a higher CO_2 emission price may help to mitigate this effect to a large extent.

6. Discussion and policy recommendations

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

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

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

involved. Further research is also needed with regard to the use of locational pricing to incentivize additional resource efficiency. Current zonal and country level pricing dilutes locational incentives for demand-side load modification.

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

Acknowledgments

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