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ORIGINAL ARTICLE

Energy Efficiency First in the power sector: incentivising consumers and network companies

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Abstract Energy Efficiency First (EE1st) is an important concept that, if implemented, will minimise the cost of the energy transition by exploiting the end-use energy efficiency and demand response potential of end users. The power sector is particularly relevant for the application of the EE1st principle as it needs to be decarbonised early, demand is to grow due to the electrification, and due to the increasing value on demand flexibility to maintain system balance. In this paper we show that consumers need to be considered as multiple resources for the power system and examine key regulatory tools to mobilise consumers to offer their flexibility and DSOs to use this flexibility to reduce the need for network asset investment. The pricing of energy and network is key in delivering demand-side flexibility. At the same time DSOs need to consider them in their network planning by law, and regulators are encouraged to incentivise them to integrate the consumers in network operation innovatively. The European regulation provides an appropriate framework for the implementation of the principle in the power sector. It is now the tasks of national regulators to implement them effectively.

Keywords Energy Efficiency First · Power · Demand-side resources · Flexibility · DSOs

This article is part of the Topical Collection on Making the Energy Efficiency First Principle Operational

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Introduction

Even though Energy Efficiency First (EE1st) is considered to be an established principle in European Union (EU) legislation, it is less so in the mindset of actors across the energy value chain. Applying the simple idea behind EE1st consistently in decision making proved to be a major challenge so far. Mandatory reporting on EE1st, for example, does not go further than use of the term in the National Energy and Climate Plans submitted by Member States in 2020 (European Commission 2020a). However, the integration of demand-side resources is crucial for a quick and least-cost energy transition by reducing and flexing demand. The European Commission published a guidance to close this implementation gap (European Commission 2021).

EE1st is more and less than energy efficiency (Pató et al., 2019b). It is "more" than traditional energy efficiency programs in that its logic applies across many areas of energy policy making and energy investment that are not themselves primarily aimed at reducing energy use. This includes topics such as power market design, power and heat network planning, and resource adequacy assessments (Zondag et al., 2020). It is "less" than an efficiency-only policy in that it does not command efficiency-only outcomes. EE1st requires decision makers to thoughtfully consider demand-side resources as an alternative to supply-side resources prior to investment decisions and requires that those demand-side options be implemented whenever they are more cost-effective than the supply-side solutions they replace (Mandel et al., 2022; Pató et al., 2019b). Investing into generation and network infrastructure that can be avoided by demand-side options does not only mean unnecessary capital expenditures but often runs the risk of becoming stranded, especially in the case of fossil fuels (van der Ploeg & Rezai, 2020).

EE1st is a new term but not a new concept. Integrated Resource Planning (IRP) of power systems that was introduced in the USA to avoid the overbuilt of generation capacities and meet environmental goals at the same time recognised the role of demand-side options (Duncan & Burtraw, 2018). The substitution of network investment with non-wire solutions[1] is an expanding practice in the USA, especially in those states (mainly California and New York) where legislation requires utilities to consider these options in their development plans (Frick et al., 2021). Since 2008, the first FERC order (no. 719) on eliminating barriers to the participation of demand response in organised markets, federal regulation developed on distributed energy resources (DERs) (including demand response). Its latest Order 2222 (FERC, 2020) tries to close the regulatory gap on DER aggregations participating in the wholesale energy, capacity, and ancillary service markets (Brown & Chapman, 2021).

Even though the concept of demand-side resources includes demand response and end-use energy efficiency as well, in the power sector the former has special importance since supply and demand need to be maintained in constant balance (Cretì & Fontini, 2019).[2] This second-by-second equilibrium increases the need for flexible load in a power system increasingly dominated by variable renewable generation, both for short-term operation and long-term system planning perspectives. Demand, which has been considered inelastic for long time, is an important source of flexibility as consumers do respond to price signals (Faruqui et al., 2017). Whereas demand response can be mobilised in a short time frame, end-use energy efficiency is a demand/side resource primarily relevant for a long-term perspective (deferring network infrastructure) as it means permanent load reduction.

Exploiting the untapped energy efficiency and demand response potential in Europe (Knoop & Lechtenböhmer, 2017; Gils, 2014; European Commission, 2016) would bring significant benefits. Buildings are the key source of demand response and remain so in the future. IEA forecast that building will have approximately twice as much flexibility potential in 2040 than transport, industry, and agriculture together (IEA, 2020).

A swift power system transition relies on the active involvement of all actors and regulation has a prime role in realigning the interest of these actors to the goal of reaching a decarbonised European power system ahead of the 2050 economy-wide net zero target.[3] What are the key regulatory tools to activate consumers to offer their flexibility and distribution system operators (DSOs) to use this flexibility? This paper first discusses the multiple ways consumers can be a resource for the power system. Then it looks at key regulatory tools to incentivise (a) consumers to supply and (b) DSOs to use demand flexibility. The paper also provides some best practice illustrations of these regulatory tools. Our findings are based on the review of academic and policy literature, interviews with practitioners both in the EU and the USA in the framework of the Enefirst project.[4]

Consumers as multiple power system resources

It is fundamentally consumer choice that drives power systems both on the short, operational and the

[1] Non-wire solutions are DERs that can be solicited by network companies (utilities) to defer network investment. DERs also include demand resources (such as energy efficiency, demand response), distributed supply (PV, micro-CHP), and storage.

[2] The US discussions usually consider demand-side resources together with distributed generation and small-scale storage together as DERs. The underlying rationale is that they appear jointly as net load reduction for the power system.

[3] The EU wants to achieve the carbon neutrality of the power sector by 2040 (European Commission 2020b). The International Energy Agency has demonstrated that respecting the Paris Agreements means reaching zero emissions in the power sector in industrialized economies by 2035 (IEA 2021).

[4] www.enefirst.eu

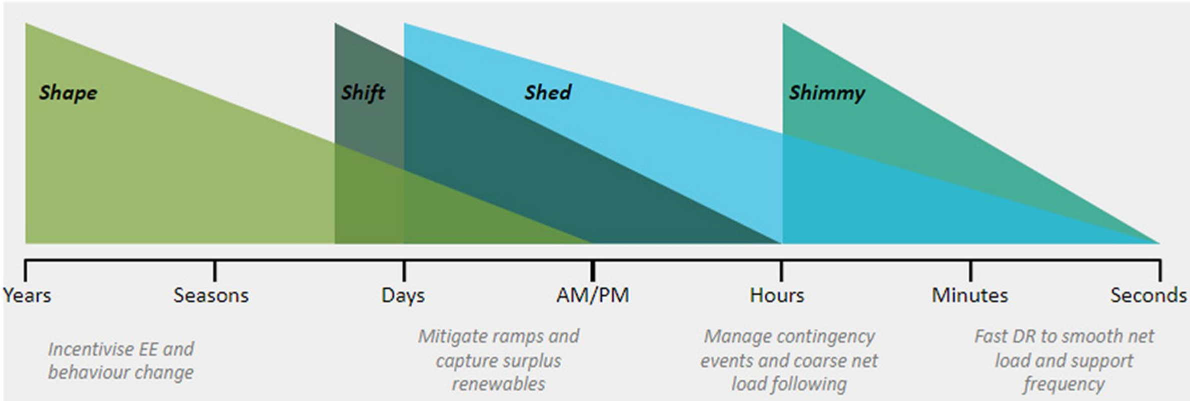

Fig. 1 Services of demand-side resource in power systems at different timescales. *Source*: Alstone et al. (2017)

long, investment horizon. Consumers have discretion on how much electricity they consume and when. Naturally, this is a function of the level of desired energy service and his/her capabilities to acquire it in different ways (being able to finance energy efficiency investment for a lower bill or invest into smart appliances to be able to sell his/her demand flexibility). These behind-the-meter investment decisions made by consumers include all energy consuming or generating assets such as space and water heating, electrical appliances, lighting, photovoltaics (PV), micro-storage, automation, and smart meters allowing demand response. Due to self-consumption, the electricity generated by PVs and the consumption constitute the net load at the distribution system level.

Consumer choices have repercussions along the entire power supply chain. They alter the needed volume and timing of power supply, and the infrastructure generating and delivering it to the consumer. Hence, the policies and regulation influencing the energy use and production of end users have important upstream implications that need to be considered systematically in those decisions to arrive at an optimal asset portfolio. Households that electrify their heating or change their internal combustion engine car to an electric one, for example, will use both the distribution network and the whole power system differently by the additional demand created and changing the load pattern depending on tariff design (Maier et al., 2019). In-front-of-the-meter infrastructure decisions — pertaining to generation, energy transmission and distribution, and utility scale storage — are taken by utilities, including both regulated network companies, and generators and storage owners operating under market conditions. Ideally, they all incorporate the behind-the-meter decisions of a multitude of consumers for efficient investment and operation. In particular, DSOs can use consumer flexibility and energy efficiency to operate the grid more efficiently, reaching higher utilization rates and minimise the needed grid expansion to cope with additional load of heat and transport electrification.

Demand as a system resource does not stop at peak shedding at emergency situation that has been its major utilisation in the past but is capable of providing various services on different timescales at a continuous basis (Hledik et al., 2019). Figure 1 illustrates the various possible services provided by demand for the power system as a whole.

Shape captures demand-side resources that reshape the underlying load profile through relatively long-run price response and demand-side management (DSM) measures that result in structural changes to the stock of loads. For example, utilities or government can use energy audits, information provision, or subsidies to incentivise consumer adoption of energy-efficient equipment (Gellings, 2017). In the USA, utilities are required to invest into energy efficiency in the framework of integrated resource planning to provide a resource plan for least cost energy service (Gellings, 2017). Energy efficiency obligation schemes (EEOS) in Europe, similarly, require suppliers or DSOs to achieve a predefined level of final energy savings amongst consumers (Fawcett et al., 2019). *Shift* represents demand response that induces the shift of energy consumption from times of high demand and tight grid capacity to times of day when there is surplus of renewable generation and/or grid is available. This can smooth net load ramps associated, for example, with the evening phase-out of solar generation. Shift technologies include, for example, behind-the-meter storage, rescheduling electric vehicle charging or pre-cooling with air conditioning and ventilation units (Michaelis et al., 2017). *Shed* describes loads that can occasionally be curtailed to reduce peak capacity and support the system in emergency or contingency events, without compensating the load reduction at another time. Examples are interruptible industry processes, advanced lighting controls, air-conditioner cycling, and behind-the-meter storage. *Shimmy* involves using loads to correct the real-time, continual gap between expected demand and actual demand at timescales ranging from seconds up to an hour by means of advanced lighting, fast response motor control, and EV charging (Alstone et al., 2017). Whereas shedding load is usually a one-off reduction, shimmy is a continuous, bidirectional adjustment of load to follow net load changes and assist in frequency control. Even though each system service has its own typical timescale, they partly overlap: the power system can require both shedding for ramp management and shifting to match renewable production on an hourly basis.

Incentivising the consumer

Consumers are having more and more flexible assets such as electric vehicles and heat pumps. At the same time, their flexible use increasingly becomes hassle-free due to automation. Consumers are essentially interested in reducing their electricity bill without compromising their desired level of energy service. Stacking the various values the use of demand-side resources create for the power system and remunerating them is key in arriving at a high enough level of bill reduction to incentivise consumers to use them (Lazar & Colburn, 2013). This section discusses regulatory incentives to mobilise consumers to become multiple system resources.

To “shape”

A fundamental tool to shape load is to expose consumes to energy prices that are based on market fundamentals. Prices kept artificially low for residential consumers results in higher than optimal consumption and is a major impediment to energy efficiency improvements. Even with cost-reflective prices, the multitude of market and behavioural failures (Gillingham & Palmer, 2014) justifies incentives and support for reaching an optimal level of energy efficiency investment. The involvement of utilities in energy use reduction depends on the market structure of the power sector. In the USA, several states require utilities to reduce a certain amount of energy amongst their consumers (Gellings, 2017). DSM programmes implemented by utilities mainly focus on energy efficiency improvement in the residential and commercial sectors. In the former, they provide incentives to switch to more efficient appliances (Aniti, 2019). In Europe, most member states use EEOSs that impose similar energy saving requirement on energy companies. The European legislation provides flexibility with regards to the obliged network companies or retailers but almost all countries opted for retailers (Broc et al., 2020; Fawcett et al., 2019). Even though network companies have better access to consumption data, retailers are better suited to extend their portfolio of activities with this new service both legally (network companies are not allowed to engage in competitive activities under European law) and also commercially to evolve into energy service companies. The experience with EEOS in Europe confirmed that this is a cost-effective way to reduce energy use (IEA, 2017; Rosenow & Bayer, 2017).

To “shift” and “shed”

As noted above, the way consumers use energy in terms of quantity and pattern of use over time has important ramification to the necessary level of generation and electricity network infrastructure. Any incentives altering consumer behaviour towards a pattern that limits the capacity expansion need for upstream infrastructure has a system level benefit to all consumers in the form of lower network tariffs and lower wholesale prices at peak periods. Price — as a key trigger of consumer behaviour — hence needs to reflect the marginal cost and thus scarcity of both

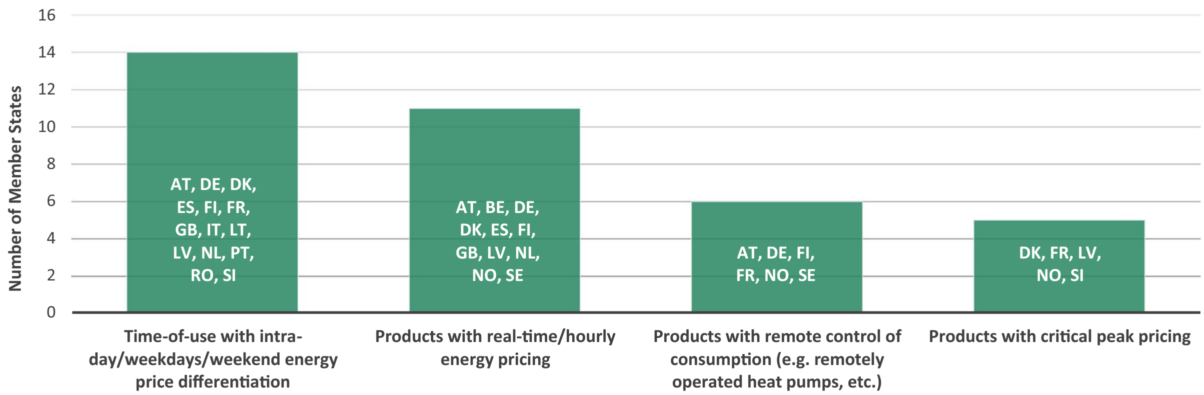

Fig. 2 Types of electricity products enabled by smart meters available in EU Member States and Norway, 2020. *Source*: ACER/CEER (2021)

of energy supply and network operation. In principle, prices must be low when there is abundant electricity supply and network capacity and high in tight periods.

Tariffs, both retail and network, need to be designed in a way that make the choices customers make to optimise their own bill consistent with the choices they would make to minimise system costs (Lazar & Gonzalez, 2015). The energy component should reflect the changes in the scarcity or abundancy of electricity supply over time by moving away from a flat rate to time-differentiated tariffs (IRENA, 2019; Paterakis et al., 2017).[5] Such tariff designs are gaining foot in Europe, not independently from the fact consumers possessing smart meters are entitled to have at least one dynamic price contract offer, and every supplier with more than 200,000 consumers must have a time of use tariff offer for final consumers (European Union 2019a, Art 11(1)).[6]

Whilst time of use (ToU) and real-time pricing is mainly used to "shift" load, remote control and critical peak pricing target "shedding" of load in those few hours when the system gets critically tight. The latest survey of ACER shows the variety of energy pricing designs in Europe (Fig. 2).

Distribution network tariff design has been the subject of growing interest amongst regulators and academic experts recently as well (ACER, 2021; Brown & Sappington, 2018; Pollitt, 2018; Schittekatte, 2020). Key design questions relate to the format (energy, capacity, fixed, or any combination), the temporal variability (flat or time of use with different granularity), and locational specificity (uniform or locational). Applying the scarcity argument to network charges implies that consumers pay for the network in proportion to their actual use and the associated costs they cause. Both flat volumetric and fixed charges (beyond the fixed charge of metering and billing) that are most often non-coincidental demand charges are economically inefficient and promote consumption at times of stress on the grid and neutralise energy efficiency efforts (LeBel et al., 2020). As a result, growing (peak) demand drives excessive investment in underutilised grid infrastructure. A uniform fixed tariff tends to shift costs from the high-usage customers in a customer class to the low-usage ones (Kolokathis et al., 2018).

ACER (2021) reports a variety of design across Member States: three Member States (MS) apply an energy-based only charge for all network users and eight Member States apply a combination of energy-based and power-based charges for users. Other MS apply a combination of volumetric and fixed charges or differentiate between consumer groups in their tariff design. In most Member States, energy-based

[5] Time-differentiated tariff has many designs (Faruqui et al., 2017). In practice it mostly means time-of-use tariffs.

[6] Some further provisions strengthen the position of active consumers. It also contains an expedited supplier switching requirement (Directive Art 12(1)) and the entitlement of individual consumers to a smart meter even in the absence of a national rollout (Art 22).

charges have a larger weight than power-based charges in the recovery of distribution costs. In eight Member States, time differentiation is applied for both the power and energy-based component of the network charge.

The EU legislation is much less straightforward in its requirements on network tariff design than on electricity tariffs. It refers to the fixed cost for networks and even though fixed costs are not equal to fixed charges, this reference is easily interpreted as justification for a (higher) fixed tariff element. It does not align with the general requirement for network tariffs that "shall neutrally support overall system efficiency in the long run through price signals to consumers and producers" and "shall not create disincentives for … participation in demand response" amongst others (European Union 2019b, Art 18(7)). Regulators shall only consider but not enforce "time-differentiated network tariffs when fixing or approving transmission tariffs and distribution tariffs or their methodologies" (European Union 2019b, Art 18(7)).

There are some examples for dynamic network charging. Radius, a Danish DSO serving about a million customers, recently has extended its ToU tariff to residential consumers as well. It aims at shifting demand away from the winter peak period and avoid or limit expensive grid reinforcements. The ToU tariffs apply to consumers with smart meters who are connected to the low-voltage and parts of the medium-voltage network.[7] Spain introduced mandatory ToU network tariffs in June 2021 for all network users. The number of households on a two-period tariff increased from 0 to 43% in 2021. The default energy tariff is a pass-through of wholesale prices (i.e., real-time tariff) and this, couples with the ToU network tariff, sends a strong price signal to consumers. Early evidence suggests that consumers have reacted to the price signal and have moved consumption from peak and flat/shoulder hours to off-peak hours (González Bravo, 2021).

Consumers need to be informed and educated on ToU tariffs as they are new to them. The California Public Utilities Commission has, for example, ordered two customer guarantees as part of the rollout: customers receive a comparison of their ToU bill and what they would have paid on their old tariff and a 1-year bill guarantee that credits the difference if the bill increased.[8]

To "shimmy"

Large-scale deployment of variable renewable generators changes the power system's ability to respond to imbalances in frequency.[9] Following a contingency event, the rotating masses of synchronous generators normally determine the immediate response to frequency imbalances. However, wind and PV are considered non-synchronous, as they have a power electronic interface with the grid, rather than a rotating mass (Dreidy et al., 2017; Tielens & van Hertem, 2016). This means that they cannot generate electricity such that the frequency of the generated voltage, the generator speed, and the frequency of the network voltage are in synchronism (IRENA, 2017b). Frequency control as an ancillary service thus becomes increasingly valuable in the power system.

Demand response can serve as an alternative option to thermal generators for providing frequency stability services. Thermostatically based controllable loads such as refrigerators, air conditioners, and ceiling heaters are suitable for such a service due to the short-term modulation of their aggregate power consumption. The thermostat modulates the power for cooling/heating to maintain the temperature nearly to the desired level. EVs as well can provide frequency response by the control of charging and discharging rates of vehicle-to-grid (Obaid et al., 2019). Batteries, as well, present a fast dynamic response to compensate the load variations in distribution networks (IRENA, 2017a).

Several EU countries already allow for the use of load, alongside with batteries and pumped hydro storage in their balancing markets (Oureilidis et al., 2020). Water heaters, for example, can be easily converted to a system resource for frequency stability.

[7] https://radiuselnet.dk/Elkunder/Priser-og-vilkaar/Tariffer-og-netabonnement/

[8] https://www.utilitydive.com/news/california-utilities-prepnations-biggest-time-of-use-rate-roll-out/543402/

[9] Frequency is the parameter of a power system that indicates whether there is an imbalance between active power generation and consumption. Sudden system failures or contingency events, such as the loss of a large generator, can cause frequency to go beyond accepted limits. These imbalances are addressed by activating power reserves, which are traded as ancillary services (IRENA 2017b; Pöller 2015).

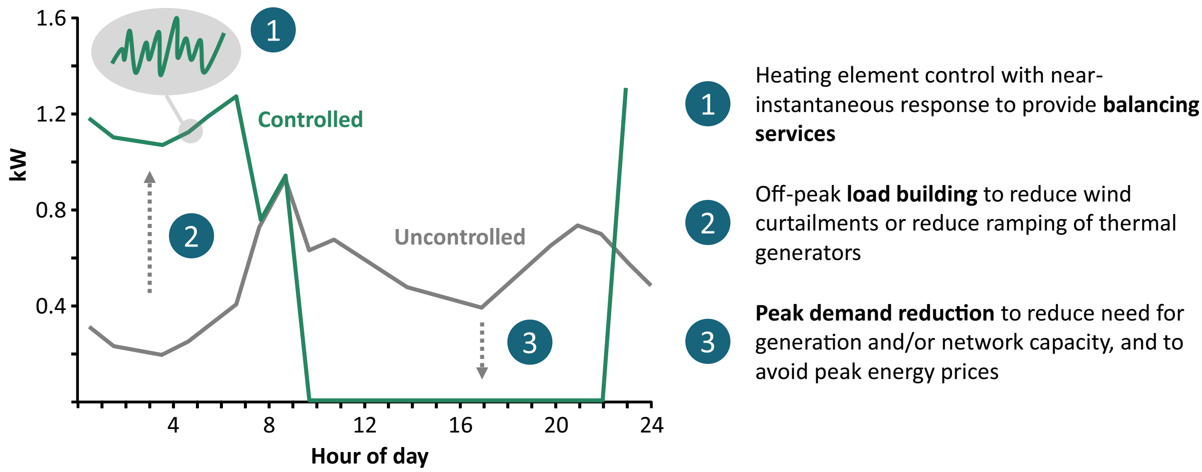

Fig. 3 Water heating load profile. *Source*: Hledik et al. (2016)

The magnitude of this relatively untapped resource is significant: in 2019, water heating accounted for 12% or 86 Terawatt-hours of the EU's electricity use in households (Eurostat, 2021). They are traditionally used as thermal storage devices by delinking the time of demand for and generation of hot water: heating up water in the tank in periods of low overall power demand (e.g., at night). Water heaters, if equipped with modern control devices, can participate in frequency regulation and grid balancing services for the power system as well (Fig. 3). These grid interactive water heaters can be controlled with near-instantaneous response from the operator, an option increasingly valuable in markets with rapid fluctuations in supply due to the large share of renewable sources.

In the framework of Fig. 1, water heaters do not only shift but also "shimmy": not only to move energy consumption from peak times to times of day when there is a surplus of renewable generation, but also to use loads to provide near-instantaneous frequency control (Alstone et al., 2017). The net benefits of a conventional grid interactive tank (considering the extra cost of upgrading the heater) triple compared to when it is only used as thermal storage for peak shaving, mainly due to the benefit provided for frequency control (Hledik et al., 2016). This, however, can only materialise if market rules allow demand-side resources to participate in ancillary service markets.

Hawaii is a nice illustration of how a traditional utility demand response programme can be upscaled to provide a much larger rollout and more services with the involvement of third-party actors. As a response to the request of the regulator, Hawaiian Electric launched a competitive tender to procure approximately 16 MW of demand response, including 2.5 MW provided by grid-interactive water heating. A software-as-a-service platform called Grid Maestro monitors analyses 5-min, revenue-grade data and optimises smart water heaters through machine learning. Grid Maestro aggregates each heater's forecasts and load shift potential into a virtual power plant of grid interactive water heaters. Automated reporting and integrated ticketing simplify performance measurement and verification.[10]

Incentivising the DSOs

It is not enough that consumers are incentivised to make use of their flexibility for the benefit of the power system, unless other actors make use of them. Once aggregated demand can participate in power markets on a level playing field, it becomes a direct competitor to generation, with markets coordinating the use of all these resources. Demand is an important resource to solve local network congestion as well. Distribution network companies traditionally forecast load changes and employ the "fit-and-forget" approach to develop their network for serving

[10] http://www.shiftedenergy.com/technololgy/gridmaestro/

peak load securely. It means that they forecast the peak load at various sections of the grid and invest into capacity upgrades (EURELECTRIC, 2013). The regulator defines and covers the eligible cost of DSOs for maintaining network operations, at the same time incentivises them to provide this service at the lowest possible cost whilst maintaining service quality by leaving the savings from the maximum eligible cost at the DSOs (revenue cap regulation).

Congestion management of the distribution network is a fundamentally new addition to the activity portfolio of DSOs. The use of demand flexibility is novel and (perceived to be) of higher delivery risk (Brown & Zhou, 2019). Why would DSOs use demand resources instead of building more cables as in the past? If they would operate on a market, they would try any new cheaper option to gain on competitors. For network companies it is the regulator that needs to mimic the market and trigger change to save on consumers' bill. The regulators have two key tools at disposal: the way DSOs are remunerated and network planning requirements to make sure that DSOs do consider demand-side resources in providing for an efficient network.

By remuneration

National regulators set the rules by which the DSOs are remunerated. The dominant remuneration scheme used for electricity DSOs in Europe is the so-called revenue-cap regulation (CEER, 2020). Under this regime, DSOs are motivated to reduce costs as the regulation decouples those costs from the revenue they are able to earn.[11] The regulator will assume an operational efficiency gain when setting a revenue cap and DSOs can increase their profits by achieving greater productive efficiency than this baseline over the price control period (Pató et al., 2019a; Rious and Rosetto 2018a).

A key barrier to use demand flexibility and energy efficiency in congestion management is that DSOs, in most remuneration regimes, have a direct incentive to relieve congestion with network capacity investment: they only earn a return on capital expenditures (CAPEX). At the same time, in the revenue cap regulation they are incentivised to reduce their operational expenditure (OPEX). Consequently, there is a disincentive for DSOs to engage in demand flexibility and end-use energy efficiency as they mainly involve OPEX and hence do not generate a return on investment (Rious and Rosetto 2018b). To incentivise the uptake of demand-side resources in the provision of network services, remuneration schemes should make DSOs indifferent to the cost type, and hence the solution they apply and place remuneration on total expenditure (TOTEX) rather than just on capital investments. As an addition, the regulation could reward DSOs with increased revenues for specified performance or, conversely, penalizing them with reduced revenues for failure to perform (cf. Performance Based Regulations (PBRs)) (Littell et al., 2018; Pató et al., 2019a).

In regulatory practice, the RIIO[12] scheme introduced in the UK in 2015 represents an important reference for PBR design for electricity DSOs in Europe. The preceding RPI-X framework, which was based on the retail price index (RPI) minus expected efficiency improvements (X) and hence focused on operational efficiency, resulted in risk and innovation averse DSOs that were judged unfit for efficiently serving the consumers in the changing energy landscape (Jamasb, 2021; Mandel, 2014). The fundamental novelty of RIIO is that it recognises OPEX in a similar fashion to CAPEX, referred to as TOTEX incentive mechanism. This creates a powerful driver for DSOs to consider the deployment of demand-side resources alongside supply-side assets in providing network services. Moreover, RIIO applies a suite of incentives from the onset of the regulatory period to improve six outputs that are deemed to be relevant by the regulator (customer satisfaction, safety, reliability, conditions for connection, environmental impact, and social obligations). Performance brings financial rewards or penalty. The new framework, coined as RIIO-2, started in April 2021 and will run until 2026 for electricity DNOs. It introduces some novel features but keeps both the TOTEX approach and the

[11] Decoupling is the term used in the USA to describe a revenue cap that breaks the link between sales volume and revenues (e.g. Sullivan et al., 2011).

[12] RIIO stands for 'Revenue = Incentives + Innovation + Output', meaning that revenues of regulated network companies should be set to deliver Incentives for cost reduction, Innovation in order to provide new services to the benefit of network users, and Outputs to improve services to network users (Rious and Rosetto 2018b).

performance incentives in place (Ofgem, 2020). As such, RIIO regulation is viewed with much interest by regulators and network operators since it demonstrates new regulatory approaches (Rious and Rosetto 2018b).

By network planning requirements

Incorporating the EE1st principle in DSO planning and operation practices means to include demand-side resources on an equal footing with infrastructure options and, more specifically, to acknowledge that energy efficiency and demand response can possibly substitute for capital-intensive infrastructure assets. Planning is aimed at identifying investment needed for the reliable operation of the system for 15 to 20 years. The European legislation requires DSOs to publish their network development plans biannually (European Union 2019a, Art 32(3)).

The planning and operation of power distribution networks is a cornerstone of decarbonisation. Electrification of heat supply and transport and the growing number of DERs such as PVs, demand response, and storage connected to the distribution grid raises the question of how to integrate these DERs to the grid at the lowest cost. These changes in network use require the reconsideration of network planning. Demand-side resources, and DERs in general, need to be incorporated as viable, granular, and probabilistic resources to be able to assess properly not only their impact on grids but also their capability to contribute to the efficient grid operation by the flexibility they are able to provide (ENEFIRST, 2020).[13] Smart grids[14] or Active Distribution Systems (ADSs) optimise the uses and flexibilities of the grid instead of passively operating it in order to limit the investment needed to serve the more volatile load (Fig. 4).

Traditional planning is based on the concept of a passive consumer and focuses where new loads will appear in the radial medium-voltage and low-voltage grid that is designed to distribute energy with a mono-directional flow of power from a substation to end-use customers. In distribution system planning, demand is exogenous and dominantly based on consumer/market information that is corrected statistically (Pilo et al., 2014). Assessment methods used are deterministic: the feasibility of connecting new customers requires the assessment of existing line capacity to incorporate them, referred to as hosting capacity analysis. These methods are mainly hourly power flow calculations for worst-case scenarios, in order to minimise risks (Silva, 2017).[15] Once the planning study is defined, different planning alternatives are assessed against the load conditions in the planning time horizon. If there is no feasible planning alternative, then the network gets reinforced. Otherwise, the least-cost planning alternative is selected. When these studies include distributed generation, the same fit-and-forget approach is applied: the relevant technical aspects of DER are considered but based on maximum generation/minimum demand scenarios that seldom occur. Demand-side integration and active distribution network options are not considered in general as alternatives to network capacity investments in the planning process.

ADS planning uses stochastic assessment, from steady state to probability and risk, and from invisible to visible and controllable DERs. First, the alternatives are planned based on real, granular, and verified consumer data that aggregates consumption, production, and storage on a temporal basis resulting in "net demand" profiles that approximate the future operation of the network more precisely than simply considering historical peak load. Flow analysis is not aimed at answering the binary question whether the network can integrate the forecasted load in the worst-case network state scenario but runs probability-based calculation to check if the predefined non-performance risk, i.e. the reliability level targeted, is exceeded or not.[16] In case of foreseen operational problems, first ADS (or in other

[13] For a good summary of the impact of DERs on distribution grids see (AEMO 2020).

[14] A smart grid is an electricity network that integrates the behaviour and actions of all users connected to it (generators and/or consumers) while ensuring an economically efficient, sustainable power system with high levels of quality and security of supply and safety (CENELEC 2020). Beyond the USA and Europe, for instance the Jeju Smart Grid demonstration project in South Korea has provided ample evidence on the practicability of the smart grid concept (Kang et al., 2018; Kim et al., 2016).

[15] Power flow analysis is also used to give insights into the expected operation of a distribution grid by calculating the currents and losses in all the branches (lines, cables, and transformers), the voltage in load buses, the reactive power in generator buses, and the active and reactive power in the primary substation in a distribution grid for a given instance.

[16] Quite similarly to generation adequacy, the level of acceptable risk should be based on the willingness of consumers/network users to pay for it.

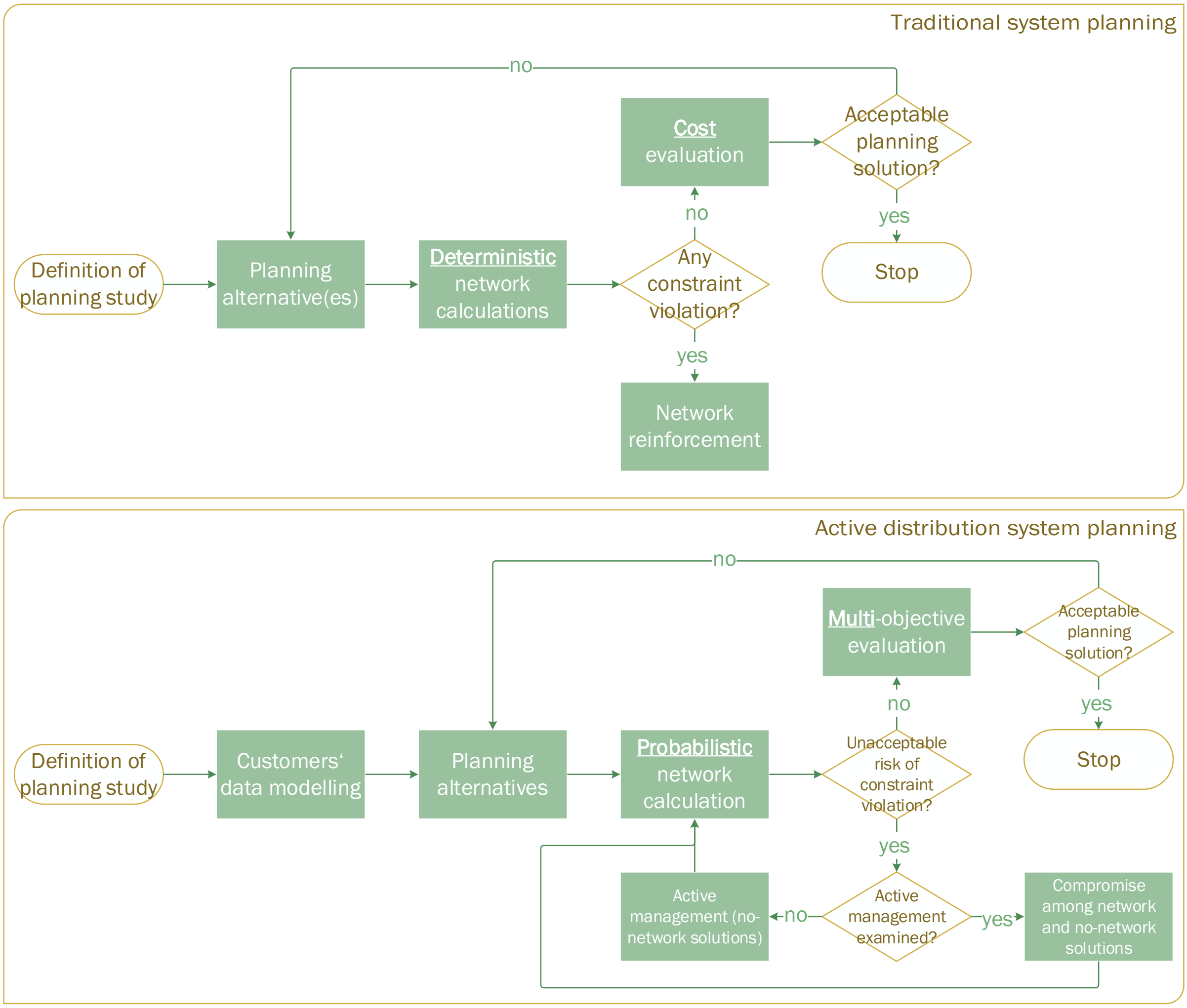

Fig. 4 Traditional vs. active distribution system planning process. *Source*: Pilo et al. (2014)

words non-wire) solutions are to be examined and only if they cannot solve the problems cost-efficiently then network investment are to be considered.

New general rules to network planning have been adopted in the European legislation in 2019 (Pató et al., 2019b). The Electricity Directive (European Union 2019a) requires that Member States must "provide the necessary regulatory framework to allow and provide incentives to DSOs to procure flexibility services, (…) in particular, from providers of distributed generation, demand response or energy storage and promote the uptake of energy efficiency measures, where such services cost-effectively alleviate the need to upgrade or replace electricity capacity" (Art 32). DSOs, on the other hand, are required to procure these resources in a non-discriminatory and competitive way. As far as planning is concerned, distribution network development plans (published every 2 years) must provide transparency on the medium- and long-term flexibility services needed, and on the planned investments for the next 5 to 10 years (Art. 32).[17] Every 2 years national regulators need to monitor and assess the performance of network companies in relation to the development of a smart grid that promotes energy efficiency and the integration of

[17] Art. 40 and 51 (European Union 2019a) set similar requirements for TSOs.

renewable energy (Art. 59). The current European requirements set a solid framework both for integrating flexibility in operation and planning and hence a major step towards the implementation of the EE1st principle. The success of integrating demand in network planning rests in the national regulators that shall develop (1) detailed rules for appraising alternatives, (2) transparency rules compatible with data confidentiality (especially with location specific data), and (3) they have to enforce the least-cost principle and make network companies to scrutinise all alternatives in a systematic fashion and provide compelling evidence for the necessity of network reinforcement.

In the USA, the California Public Utilities Commission (CPUC) introduced in 2018 the Distribution Investment Deferral Framework (DIDF) that is the process for identifying opportunities for DER to defer or avoid traditional distribution infrastructure investments (CPUC, 2018a) and report annually. In addition, utilities need to provide a 10-year vision for their grid modernization plans that not only justified the proposed investments based on lowest cost and highest benefits but also would describe whether any investments could be met instead by DER. It broadened the scope of technologies including, e.g. system analysis software and grid management systems, or sensors and controllers essential to maintain circuit stability and system reliability (CPUC, 2018b). Solicitation for non-wire solutions in California was only partly successful. So far only 15 MW has been contracted in the three request-for-offer rounds launched (January 2019, 2020, and 2021), all ending up with in-front-the-meter storage solutions exclusively (Peterson & Golestani, 2021).

Conclusions

EE1st is an important concept to minimise the cost of the energy transition by exploiting the end-use energy efficiency and demand response potential of end users. The simplicity of the concept, however, does not lend itself to simple implementation in the various energy sectors. The power sector is particularly relevant for the application of the EE1st principle for three reasons. First, the sector requires early decarbonisation by 2035–2040 to reach net-zero emissions for the whole economy by 2050. Second, electricity demand is to grow due to the electrification of heat and transport, which creates vast opportunities for applying the principle. Third, there is a constant need for equalling load and generation in the power system that places an increasing value on demand flexibility.

Demand-side resources can offer many system services with the advent of automation. As described in this paper through the “shape-shift-shed-shimmy” framework, demand response is not confined to emergency load shedding in a few tight situations annually but a multiple resource that can be used 24/7 at various timescales. For one thing, implementing the EE1st principle in the power sector means that consumers need to able to offer their flexibility: to have flexible assets that are automated plus they have the right price incentives to sell them. Dynamic pricing of electricity — as requested by the EU legislation — is not enough if energy only makes up one third of an average residential bill. Network tariffs, as well, have to communicate grid conditions through dynamic price signals so that in tight periods the use of the network cost more. DSOs will not use demand flexibility if they are not required or incentivised. It is the role of the national regulators to require the consideration of demand-side resources in network planning and to incentivise them to integrate consumers in network operation. This requires the modernisation of network company remuneration schemes in almost all EU Member States. An “EE1st-compliant” regulation guarantees that consumers can offer their flexibility and get compensated at market value and requires that DSOs use them whenever they provide more net benefit that network investment.

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Declarations

Conflict of interest The authors declare no competing interests.

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