# Regulatory and Institutional Aspects of Smart Grids

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**Learning Objectives**

- To be able to describe different forms of unbundling of generation from grids and to understand its renewed relevance in the context of smart grids and data management
- To be able to describe different approaches to network regulation including their benefits and drawbacks and to get an insight into current developments
- To be able to describe principles and predominant forms of network pricing and to get a grasp on how smart meters may influence it
- To get an insight into current and potential forms of (market-based) congestion management in smart grids.

## 1 Introduction on Electricity Market Structure

For an economist, the power system value chain consists of four main stages: generation, transmission, distribution and retail. Generation is the production and retail is the sale of electricity to end-users; sometimes, wholesale trade is considered another separate stage in the value chain. These are potentially competitive stages, where

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commercial companies can unfold market activities. In between, we find the networks; first the high-voltage transmission network and second the medium- and low-distribution networks. These are natural monopolies. A natural monopoly exists when it is cheaper to provide a certain industry output by a single firm than by several competitive firms (Baumol 1977). This is typically the case in industries with high fixed costs, which do not vary much with the output, and low marginal production costs. Applied to the energy supply industry, this means that connecting and serving all users in a certain area by one monopolistic electricity network operator incurs lower total costs as if separate competitive network operators would provide the service for subgroups of these users. There may be many such network companies, but they are all monopolies in their own services area. Figure 1 depicts these stages of the electricity value chain.

The vertical value chain sets the academic fields of regulation, competition policy, industrial organization and market design and sets the background for this chapter. The commercial companies (here generation and retail) are actors in competitive markets, for which they need access to the monopoly networks and operating systems. This network access needs to be non-discriminatory among all commercial firms. The problem arises when one of these commercial firms may be the affiliate of the network company; we call this vertical integration. The problem is that the vertically integrated company may have incentives to discriminate third parties on the commercial markets to the advantage of its own commercial affiliate: this is vertical leverage of market power (i.e., leverage from the network to the commercial stage). To address this problem, regulatory authorities have implemented rules for network unbundling: the main aim is to either curb the potential for leverage of market power (in case of vertical integration) or, one step further, to take away the incentives for this leverage by ownership unbundling (vertical separation). There are many variations of unbundling concepts, all with pros and cons; there is no single best solution. So far,

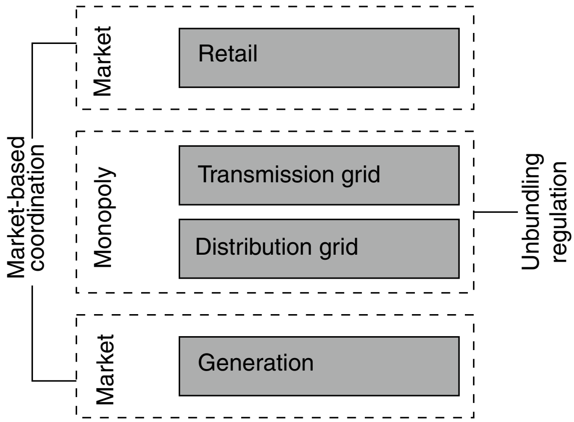


**Fig. 1** The electrical energy value chain

the discussion applied mostly to the transmission level. Following the developments to smart distribution grids, we observe that a similar debate starts at the distribution level. We discuss this in Sect. 2.2.

The networks are natural monopolies. They are subject to revenue or profit regulation for two main reasons. First, to secure non-discriminatory third-party access for all players on the commercial stages. Second, to protect the end-users against monopoly power. A regulation mechanism should set incentives for the regulated companies for efficient operation on the one hand and facilitate investment on the other hand. Several decades of practical experiences suggest that this is an uneasy combination of goals. With cost-based and price-based approaches, we find two basic regulatory models; these are extremes and, in practice, we find many hybrid forms. Interestingly, arguably driven by the energy transition, following the new trend that network operators are facing many new task and roles, a new type of regulation is currently developing: output-oriented regulation. We discuss this in Sect. 3.4.

Network users, be it companies or end-users, pay for network usage for different reasons. First, the networks need to be financed. Second, network charging sets signals for the network users to optimize short-term use and long-term development of the network. For a long time, the networks were mostly uncongested. This has changed: network congestion is rather the rule than the exemption. Network congestion management now tries to set signals for optimal short-term network use and optimal long-term investment. Here is where smart network pricing and contracting and smart markets step in. A topical development is decentralized congestion management: network congestion increasingly needs to be managed with congestion-relieving demand and supply at the distribution level; we call this flexibility. The current debate is how to organize decentralized flexibility markets to relieve network congestion. We discuss this in Sect. 4.2.

## 2 Governance Models for Smart Grids

Within the last decades, the electricity supply chain (compare Sect. 1) was primarily shaped by the liberalization process (Joskow 1996). Before liberalization, a hierarchical and integrated system existed in the electricity sector. Utilities were active in all stages of the supply chain with one and the same vertically integrated company. However, in their seminal work in 1983, Joskow and Schmalensee (1983b) point out that the introduction of competition in generation could increase the overall efficiency of the electricity sector, which started a process known as structural reform. The extent of this structural reform differs between countries; we focus our analysis on the structural reforms in Europe and add experiences from other regions where appropriate.

### 2.1 *The Structural Reform of the Electricity Supply Chain in Europe—Before Smart Grids*

Today, network unbundling is the norm in Europe: unbundling describes the separation of the natural monopolies (i.e., electricity networks) from the competitive parts of the supply chain (namely, generation and retail). In its most extreme form, this means that the unbundled networks are owned and operated by (independent) companies that are not active in generation or retail. Or vice versa, generation or retail companies do not own the networks. The liberalization process in the European Union on the transmission level involved three steps, starting with the First Electricity Directive of 1996 (European Commission 1996), which was followed by the Second Electricity Directive in 2003 (European Commission 2003) and the Third Directive in 2009 (European Commission 2009). The European Commission pursued four goals by liberalizing the electricity market (for details see Meyer 2012): The main goal of the liberalization process in the EU was to establish a single European electricity market. Second, liberalization was established to secure third-party access to the markets in generation, trade and retail. Third, third-party access to the network infrastructure was regulated to prevent discriminatory behaviour by network owners against other generation and retail companies (see Sect. 4). Fourth, final customers should be allowed to choose their electricity supplier, called retail competition.

The results of the structural reforms in Europe differ between the network levels, the transmission and distribution networks.

**The Institutional Framework on the Transmission Grid Level**

The current institutional framework in the EU is based on the 3rd legislative package (European Commission 2009). Thereby, the Commission introduced three different options for unbundling on the transmission level, i.e.

- ownership unbundling,
- (deep) Independent system operator (ISO),
- Independent transmission operator (ITO)

Figure 2 provides an overview of the different governance models, which include the three options above. We will introduce the other governance models later in this section. Full ownership unbundling prohibits joint ownership of network and generation or retail assets within one firm.

The ITO model allows companies to retain both network ownership and management, but it puts strong limitations on cross involvement of employees to assure independence of the network. The ITO scheme is in effect a stronger form of legal unbundling. Legal unbundling was introduced in the Second Electricity Directive in 2003 (European Commission 2003) and requires that the network operator is independent at least in terms of its legal form, organization and decision-making from other activities not relating to transmission (i.e., generation and retail). This includes unbundling of accounts, operations and information. The idea behind this is to ensure that no relevant information is exchanged between the network and other parts of the supply chain within one utility. One can think of legal unbundling as “firewalls”

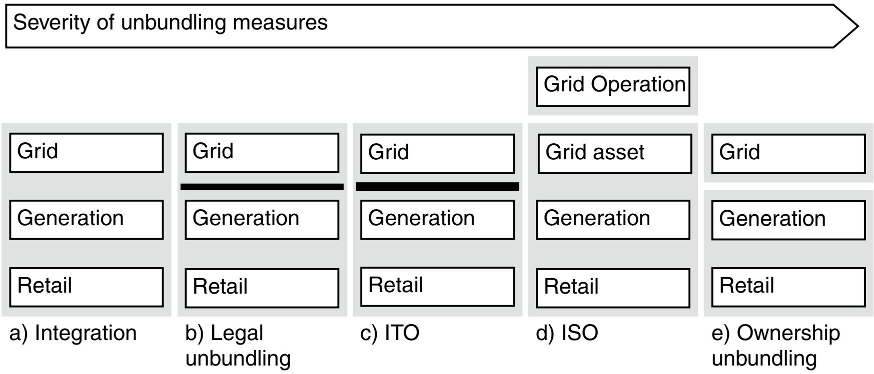


**Fig. 2** The different unbundling schemes in the electricity sector and their degree of vertical separation. **a** Applies to all DSOs in Europe that serve less than 100,000 customers. **b** All DSOs with more than 100,000 customers are legally unbundled. **c** ITO is a stronger form of legal unbundling. **d** Ownership unbundling describes the full separation of the networks from all other parts of the supply chain. **e** ISO separates network ownership (still integrated) from network operation (separated)

or "Chinese walls" which prohibit such a flow of information within one integrated company (Brunekreeft and Keller 2001). Still, a legally unbundled network operator can be part of a holding company that owns generation and retail subsidiaries as well.

Conceptually, we can think of a transmission system operator (TSO) to consist of the owner of the transmission assets (TO) and the system operator (SO). These are usually one and the same company, but that need not be. The unbundling option ISO requires that an independent entity takes over operational activities (system operation) in the network, separate from transmission asset ownership. With an ISO, the network ownership can stay with the integrated firm, which also owns generation assets. The primary task of the ISO is scheduling and dispatching generation and load and the allocation of scarce transmission capacity. In addition, the ISO cooperates with the transmission owners and other stakeholders to coordinate maintenance schedules and plans new transmission investments together with the transmission owner. As the ISO has no direct interest in the financial performance of the owners of any of the assets that comprise or utilize the transmission network, it can be expected to be neutral (Balmert and Brunekreeft 2010).

In Europe, transmission system operator (TSO)s are either ITOs or ownership unbundled. With very few exceptions (e.g., the UK), the ISO model is not applied in Europe. Rather, the ISO model is the standard in the US, where the transmission networks as operated by independent ISOs, so-called Regional Transmission Organisation, but the network assets are owned by separated utilities that own both, the transmission and distribution networks, in addition to generation and retail.

**The Institutional Environment on the Distribution Grid Level**

In Europe, as well as in the US, the institutional environment on the distribution grid level is different compared to the previously described framework on the transmission level. In the EU, distribution networks are currently subject to legal unbundling as a minimum requirement (European Commission 2009). However, legal unbundling is only applied for those DSOs that have more than 100,000 customers. DSOs with fewer customers do not have to unbundle and can remain an integrated part of a utility. This exception is known as the de-minimis rule (specified in European Commission 2009, Art.26). Out of the roughly 880 DSOs in Germany, for instance, only a small share (about 150) has such a large customer base, which, in turn, means that roughly 80% of all DSOs are still part of integrated utilities (European Commission 2011). It needs to be noted that the legally unbundled DSOs, which are not subject to the de-minimis rule, own large parts of the overall network in most member states of the EU. Typically, these larger DSOs own roughly 95% of the national networks (even though their number is quite low), exceptions are Denmark (small DSOs own 43% of networks) or Austria (12% of the networks in the hands of small DSOs). In the US, on the other hand, DSOs are fully integrated with generation and retail (in most states).

Notwithstanding the advantages of promoting more competition, unbundling does have drawbacks and was met with criticism. Joskow and Schmalensee (1983a) already stressed that the unbundling of the networks will require complex coordination mechanisms (i.e., contractual relations) to substitute the previously internal planning processes of integrated utilities. At the heart of the discussion about the coordination mechanism are transaction costs, which are the costs related to establish a contractual relation, e.g., the costs to identify partners, define the contract, etc. (see Coase 1937; Williamson 1979, for details on transaction cost theory). Basically, information exchange in integrated utilities results in lower transaction costs as does the information exchange between separated entities, as long as the market has not established efficient coordination mechanisms (i.e., low transaction costs). In the electricity sector, coordination becomes especially relevant at the intersection between the networks and the electricity generation market. Here, a coordination problem evolves due to missing information exchange between the generation companies and network operators (see Brunekreeft 2015, for details). The result of the missing information exchange and the weak coordination mechanisms is an increase in costs and a decrease in efficiency, especially on the distribution grid level. Although the coordination problem has originally been a consequence of the liberalization process, its relevance increases with the diffusion of distributed generation based on renewable energy sources (RES) as the number of parties that need to be coordinated within the network increases.

With smart grids, from an institutional perspective, the challenge arises to find the right balance between two general principles: On the one hand, the institutional framework should facilitate a level-playing field, which means that all market parties, be it an incumbent energy utility that operates conventional power plants or a new market entrant that makes use of smart meter data to develop new energy services, have the same access to the electricity infrastructure. This implies that all relevant information available to the network operators, as long as this information has commercial value, is available to all market parties in a non-discriminatory way. Data on the flexibility need by DSOs is one example of such information which gains significant commercial value in smart grids. Hence, the EU Commission now requires each DSO to publish network development plans that provide information on the mid- and long-term need for flexibility (European Commission 2019). While access to networks is not a new regulatory task, access to smart meter data, for example, constitutes a new requirement for a level-playing field in smart grids. To put it differently: With smart grids, the requirement to facilitate a level-playing field extends beyond the traditional access to the electricity networks, e.g., into the digital realm as well. For example, DSOs in Europe and in the US are responsible for the smart metering infrastructure, and hence the level-playing field extends to equal access to smart meter data infrastructure as well. On the other hand, the requirement for coordination increases with smart grids as well. As described above, coordination here refers to the information exchange between the network operators and the network users. With decentralization and digitalization, the number of network users that become part of this coordination process increases. For example, distributed generation results in hundreds of thousands of independent generators, while the digital connection of electricity devices (from smart assistants to connected heat pumps, etc.) is on the rise as well. As a result, the coordination process in the electricity sector now involves a multiple of actors compared with the coordination process ten years ago.

In general, coordination within an integrated company has two advantages: First, it is relatively uncomplicated, since the different departments can just talk to each other. Second, the incentives are aligned between the different departments, since they all work for the same overall profit. Imagine an integrated utility that owns generators and networks. To coordinate the generators with the networks, e.g., to reduce the overall costs of the integration of an additional generator into an existing grid, these two departments only need to meet and exchange information in an internal meeting. Since both departments want their company's profit to increase, the incentive to cooperate will be strong. The transaction costs of this process are rather low since there is no need for a long search, etc. However, now imagine that the network operator and the generator are two independent companies, in this case, coordination cannot be facilitated by internal communication processes and the incentives are not aligned, since the separated companies focus on their own and not their combined profit. Hence, market signals are required to coordinate the investments of these two companies. If these market-based coordination mechanisms are not efficient and do not align the incentives of the involved companies, the transaction costs for coordination will be higher than in the integrated case, which, in general, is an argument for integration. However, with integration, it is more difficult to secure competition. The regulator will have a hard time to secure that the integrated network operator does not favour its integrated generator, e.g., with respect to connection charges. Hence, there is a trade-off between coordination on the one hand, and facilitating a level-playing field on the other hand. With smart grids, both criteria gain significant importance on the distribution grid level, which now drives a new debate about the level of integration/unbundling on the distribution grid level to facilitate the development of smart grids. In other words, the question is raised (and not yet answered) whether the trend towards smart grids requires an adaptation of the unbundling regime of DSOs in Europe.

## *2.2 The Governance Options for Smart Distribution Grids: What Changes in Smart Grids?*

With smart grids, the DSOs tasks can extend beyond the traditional development, maintenance and expansion of electricity networks. For example, DSOs could take care of smart meter data management or the operation of multi-use battery storage. With these new tasks, the search for the efficient balance between facilitating a level-playing field and coordination becomes more complex. Hence, regulators in Europe are discussing whether further unbundling is deemed necessary and if so, how these unbundling models should look like. In general, the different unbundling regimes for the transmission level presented in Fig. 2 can be adapted to the distribution grid level as well.

However, the alternatives to the current legal unbundling of distribution grid operators all come with certain challenges. For example, ownership unbundling, which is the strongest form of unbundling, has not yet proven to be an efficient solution. De Nooij and Baarsma (2009) provide a cost-benefit analysis of ownership unbundling in electricity distribution networks, based on experiences from the Netherlands. They conclude that the ownership unbundling comes with potentially very high one-off and structural costs (e.g., for implementation of ownership unbundling rules), while current literature suggests that the related benefits might not exceed these costs. To put this differently, though ownership unbundling might be the best way to secure a level-playing field for smart grids, the potential increase in transaction costs to fully unbundle the DSOs and for coordination might exceed these benefits (Nillesen et al. 2019). Hence, from today's perspective, ownership unbundling might not be the ideal solution at hand to facilitate smart grids.

As a (less strict) alternative, the Independent distribution system operators (IDSO) model is currently discussed in the US in the context of smart grids (Burger et al. 2018). The IDSO depicts an application of the ISO model (as introduced above) to the distribution grid level. With the IDSO concept, asset ownership is separated from system operation. The asset of the network can be owned by an integrated company. System operation is delegated to an independent operator: the IDSO. Independent here means that the IDSO is not owned by or affiliated with market parties from retail, generation or other market parties like aggregators (Friedrichsen 2015). Though the concept of IDSOs is discussed more frequently with increasing decentralization, Burger et al. (2018) point out that the separation of asset ownership and operation would probably result in a lower system efficiency compared to an integrated solution. These inefficiencies are due to several key challenges that are associated with the ISO model in general, and which are relevant to the IDSO concept as well. Pollitt

(2012) summarizes these key challenges for the ISO model. Here, we point out two weaknesses of the ISO model described by Pollitt (2012) that would be relevant for the IDSO model as well:

- Complex information exchange and potential duplication of tasks: the system operator and the asset owner both need to have a highly complex system of information exchange. With smart grids, the complexity of information exchange (data exchange) will increase significantly, which potentially will raise the duplication of tasks as well.
- Costly dispute resolution procedures: if operation and asset ownership are separated, the risk allocation process can reach very complex levels. In the case of congestion management (see Sect. 4), the question about liabilities becomes very important, since the costs for the different measures (e.g., local congestion management vs. curtailment vs. investment) might differ significantly and disputes between asset owner and operator might evolve about the efficient allocation of costs.

Due to these weaknesses, the IDSO governance model does not seem to be a good alternative to legal unbundling on the distribution grid in Europe either.

This leaves us with the last governance model, the Independent distribution operator (IDO). The IDO could be considered as a governance option for smart grids with stronger unbundling of DSOs—corresponding to the ITO at the TSO level. An IDO is a stronger form of legal unbundling than it is currently applied in the EU on the distribution grid level. Although the network operator is still owned by an integrated company in this approach, it is an independent division with its own corporate identity, resources and management. The use of services from the integrated company is prohibited. The aim of these additional firewalls between the network operator and the other parts of the utility is to ensure independence from management and network investment decisions. According to the European Commission, an ITO at the transmission system level is a well-functioning alternative to ownership unbundling (CEC 2014). Furthermore, the expected additional benefits to switch from the ITO model to ownership unbundling are considered to be small (Brunekreeft et al. 2014). Together with the positive evaluation of the ITO model by the EU Commission, these insights serve as a first indicator that the introduction of an IDO to facilitate the development of smart grids in Europe might become a viable governance solution.

### *2.3 Case: Governance of Smart Meter Data Management in Europe*

So far, the traditional analogous electricity meters were installed, operated and maintained by the distribution network operators. The DSOs thereby served as an intermediary between the network users (e.g., the consumers) and the retailers. Due to this experience, they became responsible for installing and maintaining smart meters as well, at least in most European countries (exceptions are the UK and, at least theoretically, Germany where the metering market was liberalized) and in the US. With smart meters, the commercial value of data access on the distribution grid level increases, since smart meters collect and distribute data on local energy consumption, which might provide a basis for many new business models. Due to this increased commercial value associated with smart metering, the future role of DSOs in this context is under discussion. Different European countries are in the process to establish data management systems for smart meter data. Most of these data management systems shall provide a framework to exchange data from smart metering for billing, switching processes and new tariff designs. In different European member states, the so-called data hubs are introduced to address two primary issues:

1. secure equal access to data from smart metering
2. increase efficiency in the communication between market parties, especially between network operators and retailers for billing and switching purposes

Two prominent examples for smart meter data hubs are located in Belgium and Norway.[1]

**Belgium: Central market system (CMS)**
Since 2018, a centralized data hub facilitates the data exchange between market parties in Belgium. This CMS is operated and financed by a company called ATRIAS, which is run by the distribution system operators. The CMS connects the databases of the network operators (who collect the data from the smart meters) with the relevant and eligible market parties. Thereby, ATRIAS has a focus on the data exchange between the DSOs and retail businesses. Other parties, like the transmission system operators and third-party service providers, shall get access to the data as well.

**Norway: ElHub (Electricity Hub)**
Norway has a similar plan as Belgium to manage the data exchange from smart metering. ElHub facilitates the data exchange between market parties in Norway and is operated by the national TSO. Smart metering data is collected via the DSOs and stored in the ElHub together with consumer data from the retailers. ElHub aims at standardization of data access to smart meter data for all eligible parties. In the beginning, ElHub will provide hourly values for smart metering, but might increase this up to 15-minute values. The customers are in full control of their data, which they can access via an online tool, and thereby manage third-party access to their data sets.

Different governance approaches can be applied to govern these data hubs. Here, we separate the potential approaches into two governance categories:

- *Regulated and market-based approaches* either integrate data management systems with the existing monopolies in the electricity sector, i.e., the networks, or are established as institutional monopolies granted by the government (with one entity being responsible for the national smart meter data management).

[1] Further details can be found in CEER (2016).

- *Market-based approaches* separate the smart meter data hubs from network operation. In the market-based model, any party other than the operators of the monopolistic bottlenecks could be responsible for this task. This includes incumbents from the electricity sector, as well as third parties (e.g., from the telecommunication sector), which are not yet active in the energy business. These competing data hubs would either be subject to competition law or a regulation scheme independent from the monopolistic bottlenecks of the network industries.

The decision about the specific institutional design of smart meter data management needs to take into account several factors. For example, from an institutional perspective, the chosen governance approach shall ensure non-discrimination and a level-playing field.

## 3 Network Regulation

In Sect. 1, it has been explained that the value chain of the electricity supply industry contains market and network stages. The networks, transmission and distribution, are natural monopolies. There may be many network companies, but they are all monopolies in their own geographical area. Following the neo-classical microeconomic theory, these monopolistic networks need to be regulated to prevent the network operators to seek monopoly rents, which they could do by increasing network charges above the level required to cover their costs. Regulation of charges, revenues or profits aims to achieve two goals: first, promotion of competition on the network (generation and retail) and second, protection of the consumer and economic welfare. At the same time, the regulatory framework must consider the following constraints:

- Regulated charges should be sufficient to allow full cost recovery and thereby allow adequate new investment.
- The framework should set incentives for the network operators to maintain and improve the efficiency of production.
- The framework should set incentives to create new value, where this is beneficial for society.

The latter constraint points to a new development in regulation practice and theory. Regulation already saw a major paradigm shift in the 1980s, with the shift from cost-based approaches to price-based regulation. Currently, we may face a next step: output-oriented regulation. In this section, we will explore this development.

### *3.1 The Regulatory Lag and Regulatory Review*

In essence, regulation allows revenues to match total cost plus a fair and reasonable rate of return on capital. However, as we will explain below, if costs are simply passed

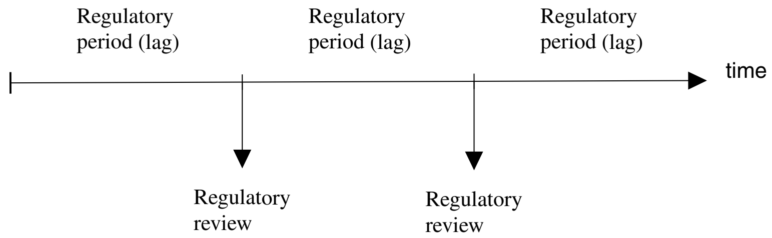


**Fig. 3** Timeline of the regulatory lag and regulatory review

through to the customer then the network operator will have low incentives to keep costs low. Therefore, regulation tried to de-link allowed revenues from the firm's own underlying costs: in that case, movements in the costs do not affect allowed revenues (and prices) and therefore the firm will have an incentive to keep the costs down. The period in which allowed revenues are delinked from underlying costs is called regulatory lag or regulatory period. On the other hand, if the allowed revenues have no relation to the underlying costs, the outcome may become unreasonable; either the firm makes excessive profits or losses. Therefore, at times, the regulation needs to re-link allowed revenues to the cost base. We call this the regulatory review (in the US, this is often called rate hearing). The regulatory timeline in Fig. 3 illustrates this.

The basic models of cost-based and price-based regulation differ in precisely this point. In cost-based models, the regulatory lag tends to be short and endogenous: the link between allowed revenues and costs is strong. Price-based models try to de-link allowed revenues and costs explicitly: the regulatory period is relatively long and exogenously predetermined. Output-oriented models extend the price-based models and link revenues to some explicit output metric, irrespective of underlying costs, until a regulatory review.

As Joskow (1989 and 2014) convincingly points out, the different types of regulation may actually be quite similar. In practice, regulation is the sum of details and it is quite difficult to give an unambiguous label.

## 3.2 *Cost-Based Regulation: Rate of Return Regulation*

Cost-based regulation has a long tradition in monopoly regulation, especially in the US. The most well-known form of the cost-based regulation is rate of return regulation, where the regulatory cost base is the capital base. Rate of return regulation allows a 'fair' rate of return on capital employed (Joskow 1974; Joskow et al. 1989). The basic formula is

$$REV = OC + d \cdot (KT - CD) + s \cdot (KT - CD) + T \tag{1}$$

where

- $REV$ is revenue,
- $OC$ is operating costs,
- $KT$ is historic capital value,
- $CD$ is cumulative depreciation,
- $T$ is taxes,
- $d$ is depreciation rate,
- $s$ is allowed rate of return on capital.

In addition, we define $r$ as the cost of capital. The allowed rate of return $s$ is to be determined by the regulator. If $s = r$, then the allowed rate of return would exactly match the investors' idea of the cost of capital. Usually, we would expect $s$ to be somewhat larger than $r$ as the bargaining outcome between the regulator and regulated firm. The allowed revenues are calculated from the regulatory cost base: the asset base, operating cost and taxes. Note that the operating costs (here $OC$, but usually denoted by OPEX) are a cost pass-through and do not have a mark-up.

In theory, the regulator sets $s$ and all else follows from this. In particular, the firm would have to calculate its own prices and revenues following the costs in such a way that the rate of return does not exceed $s$. Therefore, if the costs change, the revenues (and prices) have to be adjusted to fulfil the regulatory constraint.

Rate of return regulation suffers from at least the following two drawbacks: A first problem is the low-powered incentives of cost-based regulation. Assume that the cost-based regulation is strict and thus the regulatory lag is zero. If the management of the firm now puts effort into cost reduction, it will have to reduce prices immediately to fulfil the regulatory constraint. The reverse argument also holds; additional costs can be passed on to consumers immediately. In both cases, we should expect that the incentives to control costs are low. This is the main argument for the shift towards price-based regulation, which sets strong incentives for efficiency improvement. We discuss price-based regulation later on in this chapter.

A second problem has come to be known as the Averch–Johnson (AJ) effect (Averch and Johnson 1962), also known as gold-plating or overcapitalisation (cf. Knieps 2008, for a formal exposition). The AJ-effect is typical for the rate of return regulation and does not apply to cost-based regulation in general. The rate of return regulation restricts the rate of return on capital employed, while operating expenditure is subject to a straightforward cost-pass-through. If $s > r$, it pays off to inflate the capital base at the expense of operating costs, because the capital base determines allowed profits. The inefficiency lies in the distorted ratio of CAPEX versus OPEX, also called a CAPEX-OPEX-incentive-bias (CAPEX-bias).

The AJ-effect is well established in the literature; yet, empirically it is controversial and it has not been convincingly shown to exist (see e.g., Borrmann and Finsinger 1999). Perhaps due to the partial replacement of rate of return approaches by price-based models, the AJ-effect lost popularity and did not play a major role in the regulatory debate throughout the 1990s until about 2010. Recently, the CAPEX-OPEX-incentive-bias (short, CAPEX-bias) is back in the regulatory debate of, among other things, electricity networks. First, smart grids typically rely on OPEX measures (e.g., IT expertise, software, curtailment, demand response, etc.). A CAPEX-bias towards traditional network assets (e.g., network expansion) would thus hamper the development of smart grids in favour of non-smart network investment. Second, network operators are increasingly facing OPEX-related tasks, e.g., congestion management which increases with renewable energies and drives the need to extend the workforce for this task.

In general, there are three sets of potential sources of CAPEX-bias: First, a CAPEX advantage, especially that the rate of return is higher than the actual cost of capital, i.e., $s > r$. Second, an OPEX disadvantage; here one can especially think of an OPEX-risk that is not fully reflected in the regulation (Brunekreeft and Rammerstorfer 2021). Third, sources for a CAPEX-bias can be caused by details in the specific regulation; this is context-dependent and differs for each country.

The debate on the CAPEX-bias received new attention with an investigation of the UK water regulator Ofwat and energy regulator Ofgem around 2011. Addressing the issue these regulators developed a variation of total expenditure (TOTEX) regulation (OFWAT 2011; OFGEM 2017; Oxera 2014). The idea is elegantly simple. A predefined fixed part of OPEX is activated and treated like CAPEX: a “fixed-OPEX-CAPEX-share (FOCS)”. Under FOCS, all expenditures, whether for capital goods (CAPEX) or operational measures (OPEX), are treated equally as TOTEX. A fixed share, the capitalization rate $cr$, of this TOTEX is then “capitalized” (quasi-CAPEX) and the remaining part (here: $1 - cr$) is volatilized as quasi-OPEX (“pay-as-you-go”). This capitalization rate is given: fixed-OPEX-CAPEX-share. In the regulation, the resulting quasi-CAPEX and quasi-OPEX are treated in exactly the same way as the CAPEX and OPEX in the normal system. The quasi-CAPEX go into the regulatory capital base and generate depreciation and interest. The quasi-OPEX are booked within the book year. This way, ceteris paribus the firm is actually indifferent between CAPEX and OPEX and thus the CAPEX-bias is internalized.

## 3.3 Price-Based Regulation: RPI-X

In 1983, Professor Stephan Littlechild was asked by the British government to assess different regulatory regimes for the regulation of British Telecom, which was then to be liberalized and privatized. This resulted in what is now seen as a paradigm shift. Littlechild was quite critical of cost-based approaches and suggested price-based models instead (Littlechild 1983). The British government followed this advice and implemented what came to be known as RPI-X regulation (or, price-cap regulation). Soon afterwards, price-based models gained popularity in both practice and theory. The literature on price-cap regulation is vast. In the USA, price-based models are often called performance-based regulation (PBR) (NREL 2017).

As Beesley and Littlechild (1989) point out, the main reason for price-based models are high-powered incentives to reduce costs: hence, the expression incentive-

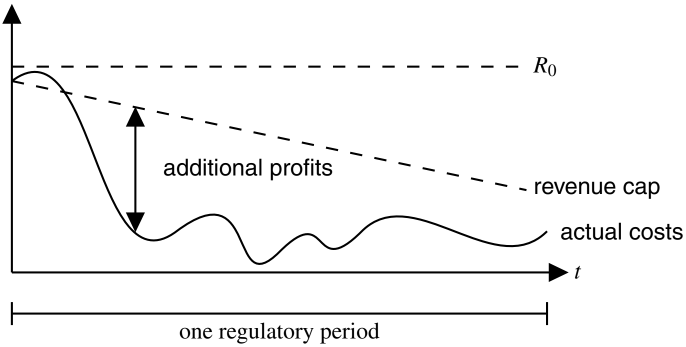


**Fig. 4** Mechanics of price-based regulation

based regulation is used frequently to describe this regulation model.[2] The key point of price-based models is to explicitly de-link allowed revenues from underlying costs. This mimics a competitive outcome as prices in a competitive setting are determined by the market (i.e., demand and the supply of all firms) and not by the individual firm.

The theoretically purest form of price-based regulation is the 'tariff-basket' (Cowan 1997). In practice, we find many variations of the tariff basket. A prominent variation is the revenue cap, as described as follows:

$$\sum_{i=1}^{n} p_{i,t} \cdot Q_{i,t} \leq R_0 \cdot (1 + RPI - X) \tag{2}$$

where $p_{i,t}$ is the price and $Q_{i,t}$ is the quantity of good $i = 1, \ldots, n$ in period $t$, $R_0$ is some initial level of revenues in starting year 0, $RPI$ is the retail price index (say, general inflation) and $X$ is the (estimated ex-ante) expected productivity increase. The periods $t$ are normally years within a regulatory control period of 3–5 years (see Sect. 3.1). This rule is applied within the control period and all variables change accordingly, but the rule itself is not changed. Revenues should follow this rule. Only at a regulatory review, which takes place at a predetermined moment, can the rule itself be changed.

De-linking allowed revenues from underlying own costs implies high-powered incentives to reduce costs. If the regulated firm manages to reduce its cost during the control period by more than what is expressed in X, it does not have to reduce prices for the additional cost reduction, but can instead keep these profits. This is precisely what sets the incentives to reduce costs in the first place (see Fig. 4).

At the latest at the review moment, allowed revenues are brought back to underlying own costs. In other words, allowed revenues are hardly ever completely delinked

[2] The term is somewhat unfortunate, as it is a misnomer. All regulatory mechanisms set incentives one way or another, and thus the term incentive regulation lacks meaning.

from own costs. The reason for having review periods and trying to relate revenues to underlying costs is straightforward. The result of complete de-linking may be unreasonable. Either it may turn out that the allowed prices are actually far too high, which questions the effectiveness of the regulation, or, what is worse, the allowed prices may be too low to recover full costs or warrant new investment. The review period gives the regulator the possibility of controlling the degree of reasonableness. However, if the revenues are re-aligned to underlying costs, the incentive problems mentioned above re-emerge: firms will try to game the regulation and inflate the cost base.

The high-powered incentives to reduce costs are well established. But there is a downside: what if costs go up? More precisely, price-based models work well to bring costs down, but have difficulty with cost-increasing investment. Theory is quite ambiguous about this, but in practice, we observe that regulators have started to adjust the regulatory models to facilitate more network investment (Brunekreeft and Meyer 2016). The energy transition increases the need for network investment, hence regulators have started to acknowledge this changing environment of network operators. The case of Germany illustrates this well. After a long debate about the low investment incentives of a pure revenue cap, the regulator changed the regulatory model: basically, the system was changed to an annual adjustment of capital costs, basically thus lifting the regulatory lag for CAPEX.[3] We observe similar moves in other countries. Perhaps the best example is the UK, where after 20 years of RPI-X regulation the system was replaced by a new system.

## 3.4 New Developments: Output-Oriented Regulation

A new development is about to emerge: output-oriented regulation, which supplements the base incentive regulation with revenue elements that reflect the achievement of specifically determined regulatory output targets or performance. Output can be anything and is broader than efficiency only. Output-oriented regulation can incentivize activities that require cost-increases and upfront expenditures and can capture external effects. We should stress that the main idea is to retain a revenue cap in the regulatory core, but supplemented with output-oriented components.

Four effects drive the development towards output-oriented regulation. First, triggered by the energy transition, network costs are increasing; the efficiency-oriented regulation is not well equipped to deal with increasing costs. Second, as pointed out by Poudineh et al. (2020), innovative activities, which have gained importance recently, face higher risks than conventional network activities. For risk-averse companies, the higher risk profile requires a move away from types of regulation (such as pure efficiency-oriented incentive regulation), which allocate a large part of the risk to the company. Instead, risky innovation activities require lower-risk types of

[3] Somewhat confusingly, it is still called "incentive regulation", although annual cost adjustment is clearly cost-based regulation.

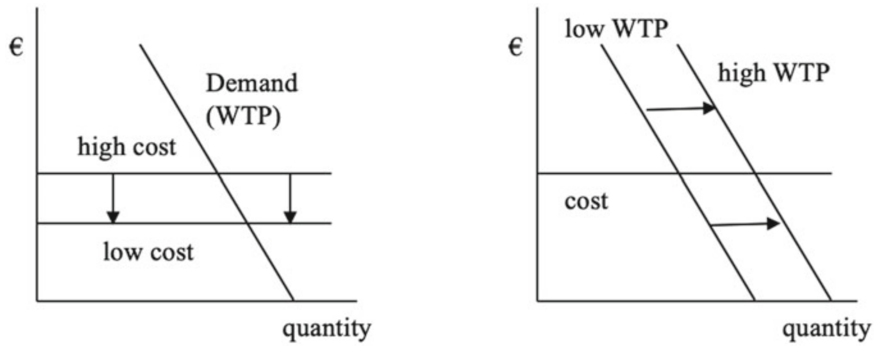


**Fig. 5** A shift of the cost curve versus a shift of the demand curve

regulation. Output-oriented regulation can balance risks between pure cost-based and price-based approaches. Third, the development and the promotion of competition has resulted in a fragmented sector. Whereas competition is unquestionably beneficial, the drawback of a fragmented sector is a loss of coordination between different actors in the sector and a lack of whole system optimization. European regulators have picked this up and call this a "whole system approach" to reflect external effects (CEER 2017b). Fourth, in practice, most regulatory models do not incentivize the development of new tasks and business models (value creation). A rationale for value-creating output-oriented regulation was (unintentionally) provided in the seminal work on quality regulation by (Spence 1975, p. 420) where he notes: "Of somewhat less interest is the case where price is fixed or taken as given. In that case, the firm always sets quality too low." To see this, note the difference between a shift of the cost curve and a shift of the demand curve (Fig. 5).

In the case of improving efficiency, the cost curve goes down, while the demand stays constant. This is what price-based models are aiming at. Things change if the demand curve shifts out: by some innovation, the product is improved, such that the willingness to pay by the consumers increases. As pointed out by Spence, price-based models, where "price is fixed," cannot deal with this situation very well. As the demand curve is shifted out, additional surplus is created (the additional area under the demand curve): "value creation." If the regulation fixes the prices, the firm cannot sufficiently recoup the additional surplus and will underinvest in product improvement. This holds irrespective of whether or not the costs increase, but the problem gets worse if costs increase. This is precisely where output-oriented regulation steps in: output-oriented regulation attempts to define and quantify the product improvement (the shift of the demand curve) by some metric and link the additional consumer surplus to additional profit for the firm and thereby set the incentives for additional value creation.

Clearly, it is challenging to set the right incentives for the economically optimal outcome. First, which outputs qualify to be incentivized? Second, which metrics should we use? Third, which incentive mechanism should we use? Fourth, how

**Table 1** Output categories under RIIO in the UK (OFGEM 2010)

| Output categories | | |
|---|---|---|
| Customer Satisfaction<br>Satisfaction of consumers, including a broad spectrum of network users, with services | Reliability and availability<br>Aspects of reliability and availability of network services that consumers are concerned with (e.g., number and duration of outages, constraints costs) | Safety<br>Compliance with Health and Safety Executive safety standards |
| Condition for connection<br>The process for new/enhanced connections to the network | Environmental impact<br>Impact of network operations on the environment (including noise/visual impacts) and contribution to environmental targets | Social obligations<br>Service to fuel poor and vulnerable consumers in line with Government requirements |

strong should the incentives be? These and other design questions are currently in the development process. A much-quoted output-driven regulatory system is RIIO in the UK (OFGEM 2010). These main groups are safety, environmental impact, customer satisfaction, social obligations, connections, reliability and availability. Note in particular customer satisfaction, which is an intriguing output-indicator. These groups are then broken down into subgroups of more tangible outputs with specific metrics, as summarized in Table 1.

In the US, beyond broad-based PBR, regulators find it useful to strengthen incentives in pre-specified targeted goals; these are called targeted performance incentive mechanism (PIM). NREL (2017) provides the following definition for these PIMs:

"*PIMs are a component of a PBR that adopts specific performance metrics, targets, or incentives to affect desired utility performance that represents the priorities of the jurisdiction. PIMs can be specific performance metrics, targets, or incentives that lead to an increment or decrement of revenues or earnings around an authorized rate of return to strengthen performance in target areas that represent the priorities of the jurisdiction.*"

NREL (2017, p. xii and pp.61) provides a long list of PBRs and PIMs being used operation in the US electric utility industry. To mention a few which are or can be of interest for the network operator:

- Incentives for implementation of renewable energies,
- Renewable energy performance metrics,
- Operational incentives: improved interconnection request response times,
- Operational metrics: incentives to improve reliability,
- Incentives to support competition.

Pfeifenberger (2010) mentions inter alia the following PIMs relevant for the network:

- "External" system costs (losses, congestion, ancillary services)

- Infrastructure investments (mains replacement, transmission, renewables)
- Non-cost goals: reliability, service quality, end-use efficiency (DSM)

At the moment, the development of output-oriented regulation is just starting and many implementation issues still have to be addressed and are issues for further research.

# 4 Grid and Market Interface: Network Congestion Management Through Pricing of Grid Use and Decentralized Approaches

In the majority of electricity markets, the price only reflects the costs of producing electricity and excludes the cost of transportation and distribution. Figuratively speaking, electricity is traded as if it could be delivered anywhere at any time. This approach is unproblematic as long as electricity grids are not congested, which has been mostly the case for a long time. When many users withdraw or feed-in electricity simultaneously, however, the technical limits of the network can be reached, i.e., the network becomes congested and cannot be expanded easily. In the distribution grids, this issue is becoming increasingly important due to the increase of decentralized renewable generation (e.g., simultaneous feed-in from wind power plants) and new electric devices (e.g., simultaneous charging of electric vehicles). To address this challenge, network congestion management is needed to set signals for optimal short-term network use and optimal long-term investment. In the following, two general approaches of network congestion management are outlined that address the interface of the electricity grid and market[4] and that are currently undergoing changes due to the development of smart grids: first, network pricing and, second, decentralized congestion management.

## *4.1 Network Pricing: Principles, Designs and Smart Grid Developments*

Being unbundled from generation and classifying as a natural monopoly, the transmission and distribution of electricity are typically priced separately and prices are regulated to prevent the monopolists from abusing their power. One purpose of charging network usage is to finance the networks. In the previous section, different regulatory approaches have been explained that can be used to determine the level of allowed revenue of the networks to achieve this aim. Another reason why network users pay for network usage is to set signals for efficient short-term network use and

[4] Another approach is integrated energy and network pricing known as nodal pricing or locational marginal pricing. For more details on locational marginal pricing, see e.g., Stoft (2002).

long-term development of the network. This purpose has become more relevant in recent years due to increasing network congestions. At the same time, the development of smart grids, giving real-time information on network usage, promises a new approach to this challenge.

Further principles for tariff design, as laid out by Bonbright et al. (1988), that are considered by regulators also include, e.g., fairness, predictability and stability. More recently, the Council of European Regulators (CEER) identified the following seven principles for the design of distribution network tariffs (CEER 2017a):

1. Cost reflectivity,
2. Non-distortion,
3. Cost recovery,
4. Non-discrimination,
5. Transparency,
6. Predictability,
7. Simplicity.

Ensuring cost reflectivity and cost recovery alone is already non-trivial when it comes to electricity networks. In the following, the first theoretical approaches and current practices of network pricing are outlined. Then new developments triggered by network congestions and smart grids are described.

Welfare maximization implies that the price of a good, here network use, should equal its marginal costs (first-best allocation) (Hotelling 1938). While ensuring allocative efficiency, marginal cost pricing of electricity networks has one major drawback: due to large fixed costs of electricity networks, marginal costs are below average costs. Marginal costs pricing would, therefore, not enable the network operator to cover her costs as illustrated in Fig. 6.

The remaining part of the costs needs to be covered differently, e.g., by an additional charge. This approach finds expression in a two-part tariff: The first part of the tariff is a charge per unit of energy (kWh) accessed from or feed-in to the grid that

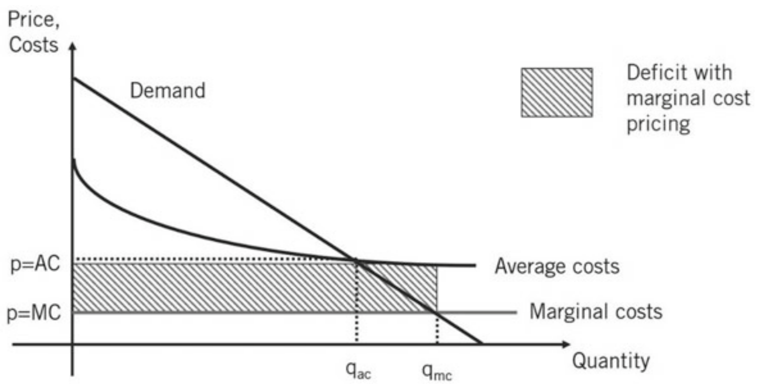


**Fig. 6** Drawback of marginal cost pricing when average costs exceed marginal costs

equals marginal cost. The second part is a charge that is independent of consumption or production, which serves to cover the remaining (fixed) costs.

Based on the approach of marginal cost pricing, but considering the constraint of breaking even is the so-called Ramsey–Boiteux pricing[5] (or short: Ramsey pricing). Mathematically speaking, prices are determined by maximizing welfare subject to the constraint that total costs are covered. Central to this concept is that users are being discriminated according to their price elasticity of demand, i.e., how strongly consumers react to a change in price. The resulting price equals marginal costs plus a surcharge, which depends on the inverse of the price elasticity of demand. This means that the surcharge increases with a decrease in the elasticity of demand (see, e.g., Borrmann and Finsinger 1999, for more details on Ramsey pricing). In other words, the more the users depend on electricity and cannot switch to other commodities, the more they pay. Those who can "run away" pay less.

Related to this approach, and partly developed by the same scholars, is the concept of peak-load pricing. The starting point for this concept is that demand for electricity and the use of the network varies over different periods (e.g., seasons or during a day or week), while the network capacity remains almost constant. Peak demand then determines the required network capacity and hence the total costs that need to be recovered. During off-peak periods the installed capacity is often under-utilized. To signal network scarcity and to prevent excess capacity, network charges need to be adjusted accordingly for each period. This is addressed in the peak-load pricing approach as follows[6]: Consider a day divided into two periods: a peak-load period and an off-peak period. Once installed, generation capacity can be used in both periods. Constant operating costs are incurred per unit per period and constant marginal capacity costs per unit of capacity. The problem is to determine the optimal output per period and the corresponding prices. The maximum output in either period determines the required capacity. If off-peak demand is very low and would at no price fully utilize the network capacity, it should only be charged operating costs while peak demand covers the entire capacity costs. Yet, if, also, during the off-peak period network capacity is fully utilized, then off-peak demand should also contribute to covering capacity costs, but only according to its willingness to pay for this capacity (see Crew et al. 1995, for more details on peak-load pricing).

In practice, tariffs often vary for different network user groups. First, electricity consumers and generators are typically treated differently, i.e., the latter are often exempted from network charges (e.g., in Germany or the Netherlands) or incur only a smaller share of network costs (e.g., 3% in France, 38% in Sweden).[7]

Second, consumer tariffs often differ for the groups of large industrial consumers (connected to the transmission grid), commercial and small industrial consumers

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[5] The approach is named after Frank Plumpton Ramsey and Marcel Boiteux: Ramsey (1927) published the result first in the context of optimal rates of taxation; Boiteux (1956) applied it to public monopolies. Baumol and Bradford (1970) synthesized the approach.

[6] Steiner (1957) addressed the peak-load problem graphically; the example given here is taken from his publication.

[7] ENTSO-E Overview of Transmission Tariffs in Europe: Synthesis 2018. Online available at: docstore.entsoe.eu/Documents/MC%20documents/TTO_Synthesis_2018.pdf.

(connected to the distribution grid), and residential consumers. For historic and other reasons (e.g., traceability, simplicity, etc.) the two- (or three-) part tariff, developed in the late nineteenth century, is still the dominant pricing structure for residential consumers in many countries, e.g., the US, Australia, Great Britain, Germany, etc. One part of the tariff is fixed, while the other is energy-based (per kWh use) and/or capacity-based (e.g., per kW connected). Depending on the proportion covered by the fixed part, the incentives for efficient grid use are rather low. In contrast, a fixed component for non-domestic consumers connected to the distribution grid is rare and even more for large consumers connected to the transmission grid (exceptional cases in the EU for the latter are, e.g., France and Sweden) (AF-Mercados 2015). The increase of decentralized electricity generation and self-supply has changed the network utilization in particular on the low voltage level. With a future increase of flexibility providers (e.g., decentralized storage) and new flexible electric devices (e.g., electric vehicles and heat pumps) new challenges will arise for the distribution networks. This development also changes the focus of network tariff design. While historically, the focus lay on the efficient allocation of fixed costs of (oversized) network capacities, in the light of network congestion and the need for network expansion the focus shifts towards incentives for network cost reducing deployment and operation. The current developments trigger a redesign of network tariff structures for users connected to the distribution grids. First, network charges may become more based on capacity than on net consumption also for small network users to prevent disincentives for households with self-supply. Second, the implementation of smart meters enables dynamic time differentiation of tariffs users and even real-time pricing for households and other small network users, which, in turn, signals actual network scarcity.

Time-varying network pricing can come in different degrees and varies from time of use (ToU) to real-time pricing (RTP). ToU pricing implies that the network charges vary for specific predefined time periods and are highest during times of expected peak demand. Several countries have implemented ToU tariffs to deal with the peak-load problem. In Europe, ToU tariffs vary between one differentiation, e.g., day and night (e.g., in Finland, Greece), up to four-time differentiated tariffs (in Northern Ireland), whereas no ToU signals are used in, e.g., Germany, Italy and Sweden (CEPA 2015).

Real-time pricing in contrast reflects the actual network usage and scarcity in real-time or at least with a much higher temporal granularity (e.g., 15 min) than ToU tariffs. Real-time network pricing has, hence, the undisputed potential to significantly increase the efficiency in network use. Concerning other principles of network pricing as outlined above, it has, however, also several shortcomings. Its dynamic nature, for instance, decreases the predictability and stability of tariffs for the customers. The uncertainty also increases for the utilities in two regards: first, the effect on the network use is not known and, second, the revenue becomes less predictable. This explains why, e.g., the German regulatory agency opposes dynamic network pricing on the basis of transparency and uncertainty (Bundesnetzagentur 2015). A way forward in this regard may be to limit the dynamics of the network pricing to certain corridors and the lead times of price changes, as well as introducing optional instead of obligatory participation in dynamic pricing (on the latter, see, e.g., Borenstein 2013).

### 4.2 Decentralized Congestion Management

Since mostly, energy pricing does not integrate network pricing, network congestion is managed by the network operator. In the long term, he/she can resolve network congestions by network expansion or upgrades. In the short term, she can undertake operational measures in order to safeguard the operational limits of the electricity grid. One of these measures is the so-called redispatch: After the closure of the energy market, the network operator examines whether the single feed-ins and withdrawals determined by the market (i.e., the dispatch) are technically feasible. If this is not the case, she can change the geographical distribution of generation and/or load patterns in order to reduce the load flow on the congested lines. To illustrate this, consider a simple network with two nodes $A$ & $B$. The transmission line connecting the two nodes has a capacity of 50 MW. A generator is connected to each node with a capacity of 100 MW each. Generator A has marginal production costs ($MC_A$) of 50 EUR/MWh, generator B ($MC_B$) of 80 EUR/MWh. Load is only connected to node B and demands 100 MW ($L_B$) for a certain hour. Energy is traded in a single market disregarding the transmission limits. In this setting, generator A would completely cover demand for that hour ($G_A = 100$ MW; $G_B = 0$ MW). The result of the energy market is shown in the left part of Fig. 7. Of the 100 MW sold, however, only 50 MW can be transmitted to node B. To stay within the technical limits, generator A needs to reduce her production by 50 MW (downward redispatch). At the same time, generator B needs to increase production by 50 MW (upward redispatch) to keep the energy balance.[8] The result of the redispatch is illustrated in the right part of Fig. 7.

Historically, power plants were predominantly large in scale and connected to the high-voltage level. That is why, still today, congestion management falls into the responsibility of the transmission system operators and is mostly conducted on the high-voltage level. The past years, however, have seen an increase in decentralized (renewable) power production connected to the lower-voltage levels. Furthermore, load connected to the distribution grid is becoming more flexible, e.g., electric vehicles or battery storage units. This has changed the network utilization, in particular, on the low voltage level and the still ongoing development is likely to put more pressure on distribution grids in the future. Against this backdrop, decentralized congestion management has gained attention in recent years as a means to integrate renewable generation and flexible demand into congestion management, as well as to address regional network congestions. The development of smart grids supports this approach.

[8] Alternatively, load could reduce withdrawal by 50 MW.

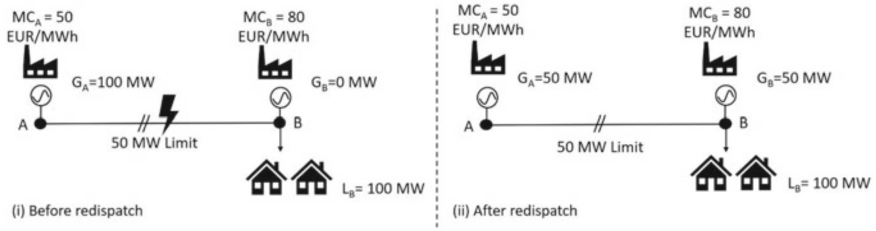


**Fig. 7** Illustration of (i) a situation with a technically infeasible energy market result before redispatch and (ii) after it is solved in redispatch in a two-node example

Currently, the design and implementation of decentralized congestion management schemes is being debated. Many options are in the discussion. Essential design elements are

- the way network congestion is communicated and how flexibility is demanded,
- the determination of compensation,
- the implementation.

Figure 8 outlines potential forms of decentralized congestion management based on these characteristics.

The network operator can request flexibility (i.e., deviation from the energy market result) passively by means of a quota. Depending on the congestion situation, i.e., over- or undersupply, all generators or all loads within the congestion region are apportioned until the network limits are reached. Alternatively, the network operator can actively demand flexibility from the local loads or generators.

The compensation for participating in redispatch can be market-based or regulated (cost-based). In the first case, supply and demand of flexibility determine the price. In the case of regulated redispatch, the compensation is determined by the regulator and can be cost-based, derived from markets or a reduction in network charges. The idea behind regulated or cost-based redispatch is to keep the electricity market and network separate from one another and to prevent the abuse of potential market power of congestion critical power plants. Redispatched units are to be placed economically in the same position as they would have been without the network operators interference, making them indifferent to redispatch. Thus feedbacks to the electricity markets shall be prevented. In Switzerland and Germany, for example, compensation for centralized redispatch is cost based, i.e., the generators are compensated for the incurred costs of upward redispatch and foregone profits in the case of downward redispatch. In Spain, transmission constraints are solved based on the bids previously committed to the energy market.

Market-based redispatch can be implemented in a separate dedicated market platform, where the network operator is the single buyer. Alternatively, an existing energy market, e.g., the intraday market, can be adjusted with locational information so as to also serve for redispatch. In the UK, for instance, the balancing market is used for

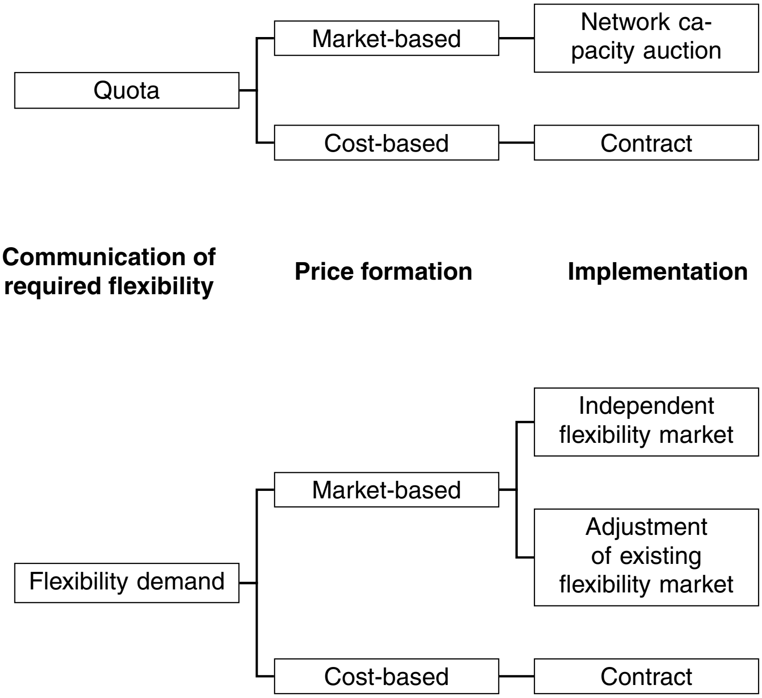


**Fig. 8** Overview on potential forms of decentralized congestion management. (based on Ecofys and IWES 2017)

centralized congestion management. Regulated redispatch is handled in a contract between network operator and flexibility provider.

New decentralized redispatch market platforms are currently tested in pilot projects in different European countries (for an overview, see, e.g., Schittekatte and Meeus 2019; Radecke et al. 2019). Whether decentralized congestion management can effectively and efficiently integrate flexible network users and relieve regional network congestions remains to be seen.

## 5 Summary

This chapter explored regulatory issues of smart grids. We have tried to strike a balance between the basics of such regulation principles and topical developments, which are triggered by the development towards smart grids. The chapter focussed on three fields. First, an electricity sector is a complex value chain with monopoly networks as platforms between commercial market areas. Various governance structures (commonly known as network unbundling) attempt to secure non-discriminatory access to the monopoly networks for all eligible parties in order to promote a competitive level-playing field. This debate is now emerging in a new dress for the distribution networks following the development of smart grids. Second, we describe network regulation, meaning the regulation of revenues and profits of the monopoly networks. We discuss different approaches (cost-based versus price-based) and, more topical, a new development towards output-oriented regulation. The latter is triggered by emerging new tasks for the network operators, which create value but are not very well facilitated under standard regulatory models. Third, we discuss the interface between the network and the market. More precisely, we discuss network charging to address network congestion. The latest development is how to adequately address decentralized network congestion: the discussion is whether we can design functioning flexibility markets.

**Governance** With smart grids, the distribution grid operators' role extends into the competitive realm of the electricity supply chain. The increasing interaction between the monopolistic networks and market activities in smart grids drives a discussion about the need for further unbundling measures. Currently, legal unbundling is the norm in Europe, but deemed to be potentially insufficient to facilitate smart grids. Ownership unbundling and the introduction of IDSO come with too high costs that might even exceed the benefits of further unbundling. Hence, the application of the IDO, an adaptation of the ITO successfully applied on the transmission grid level in Europe, might provide a balanced approach to secure a level-playing field (i.e., competition) in smart grids and at the same time a sufficient level of coordination between the networks and its users.

**Network regulation** Regulation of the revenues or profits of the monopoly network aims to protect consumers and competition. The two big variations are cost-based models (in particular, rate of return regulation) and price-based models (e.g., RPI-X). The key drawback of cost-based models is the low incentive to reduce costs. In reverse, this is the main advantage of price-based models: it sets strong incentives to reduce costs and increase efficiency. However, price-based models are not well equipped to facilitate cost-increasing activities which create new value. This is where output-oriented regulation comes in: output-oriented components supplement the base regulatory model with revenue elements that reflect the achievement of specifically determined regulatory output targets or performance.

**Interface between network and market** Electricity is predominantly traded as though it could be transported without constraints. When too much electricity is fed-in or withdrawn simultaneously, however, the network can become congested. Ensuring the efficient use of the grid is the aim of network pricing. Different network pricing approaches have been developed to signal network scarcity. In practice, however, network pricing schemes give little or no incentives for efficient network use in particular in the distribution grids. Smart grids, giving real-time information on network use, can improve network pricing at the distribution level in this regard. Apart from network pricing, decentralized congestion management based on smart grids can be used to deal with network congestion at the distribution level. Several designs for decentralized congestion management are currently tested.

**Review Question**

- Unbundling results in a trade-off between coordination and competition. With smart grids, the balance between these two on the distribution grid level changes. Why?,
- Which unbundling regime on the distribution grid level is most suitable to accelerate the diffusion of smart grid technologies? Please elaborate.,
- An important assumption for the so-called Averch–Johnson effect is that the allowed rate of return on capital is higher than the true cost of capital: $s > r$. Explain the "Averch–Johnson effect." Discuss why this is assumption important and the plausibility of the assumption.,
- Explain what output-oriented regulation is and what it tries to achieve. Briefly discuss an example of output-oriented regulation in the context of smart electricity grids.,
- The extensive roll-out of smart devices in the electricity grid (e.g., smart meters) may enable a more efficient use of the grid. Explain how this may be the case in the context of network pricing.,
- With regard to prevalent network pricing principles, real-time pricing of network usage has several shortcomings for network users and network operators. Discuss.

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