Supported by
Intelligent Energy Europe

GreenNet-Incentives

EIE/06/217/SI2.445571

GreenNet-Incentives

Promoting grid-related incentives for large-scale RES-E integration into the different European electricity systems

Deliverable D8

Report on economic incentives for grid operators in grid regulation

Wolfgang Orasch, Hans Taus
Wien Energie Stromnetz GmbH, AT

Hans Auer, Lukas Weißensteiner
Energy Economics Group (EEG), Vienna University of Technology, AT

Katerina Sardi, Tasos Krommydas
Regulatory Authority for Energy of the Hellenic Republic, RAE, GR

Bernhard Heyder
EnBW Energie Baden-Württemberg AG, DE

Sarah Davidson
IT Power Limited, UK

Wolfgang Ove
SINTEF Energiforskning AS, NO

Jaroslav Jakubes, Rita Ramos
Enviros, CZ

Katarina Vertin
ApE – Energy Restructuring Agency Ltd., SI

Botond Weöres
EnergoBanking Kft, HU

Bernhard Hasche
Universität Stuttgart, DE

Date of preparation: April 2008 (partly updated: January 2009)

Co-ordination of the project **GreenNet-Incentives**:

Lukas Weissensteiner
Scientific co-ordinator of **GreenNet-Incentives**
Vienna University of Technology
Energy Economics Group (EEG)
Gusshausstrasse 25-29/373-2
A – 1040 Vienna
Austria
Tel. 0043-1-58801-37368
Fax. 0043-1-58801-37397
Email. weissensteiner@eeg.tuwien.ac.at

Dr. Hans Auer
Project co-ordinator of **GreenNet-Incentives**
Vienna University of Technology
Energy Economics Group (EEG)
Gusshausstrasse 25-29/373-2
A – 1040 Vienna
Austria
Tel. 0043-1-58801-37357
Fax. 0043-1-58801-37397
Email. auer@eeg.tuwien.ac.at

Table of Contents

1. Introduction

1.1 The Changing Role of Electricity Grids

For many decades the electricity system has been driven by the paradigm that most of the electricity is generated in large centralised power plants,[1] transported to the consumption areas through *Extra High Voltage (EHV)* transmission grids, and delivered to the consumers through passive distribution grids that involves a *High Voltage (HV)*, *Medium Voltage (MV)* and *Low Voltage (LV)* network infrastructure (see Auer et al (2005)). In this context, the rational for splitting the electricity grid infrastructure into separate transmission and distribution grids has been the following:

- Transmission grids consist of high voltage (typically > 60-150 kV)[2] power lines designed to transfer bulk power from major generation areas to demand centres over long distances. In general, the larger the voltage is, the larger the transfer capacity of transmission grids. Only the largest industrial customers are connected to the transmission grid directly. Transmission systems have been designed to be extremely robust with built-in redundancy, i.e. the transmission system can continue to fulfil its function by alternative routing and generation in the event of several simultaneous failures of the network. In liberalised electricity markets they are operated by "Transmission System Operators" (TSOs) or "Independent System Operators" (ISOs), which are usually independent and unbundled entities operating the transmission system and being also responsible for investments into network reinforcements and extensions (but transmission grids are also subject to regulatory control).

- Distribution grids are typically at voltage levels less than 60-150 kV, responsible for the connection of consumers at smaller distances. Furthermore, distribution grids are less robust than transmission systems, i.e. reliability decreases as voltage level decreases. E.g., in practise a connection at the 30 kV level could, on average, expect to lose only a few minutes of connection per year, whereas a connection at 230 V level for a domestic consumer in a rural area would, on average, expect to lose at least an hour per year.

Up to now, there has been very little so-called "active" management of distribution grids. Rather, they have been designed and configured on the basis of extreme combinations of circumstances (e.g. maximum demand in conjunction with high ambient temperatures, which reduce the capacity of overhead lines) to ensure that

[1] One of the major benefits of big centralised power plants is the utilization of significant amounts of so-called „Economies of Scale" in electricity generation, see e.g. Auer (2008).

[2] Note, there is no common definition and strict voltage level separating the transmission and distribution grids in different regions worldwide. E.g., in Europe the voltage range from 60-150 kV separates the transmission and distribution grids, depending on the synchronised system within Europe (i.e. UCTE-, Nordel-, UK- and Irish System). More details in this context are presented on the website of the association of the European Transmission System Operators (www.etso-net.org).

even in extreme circumstances predefined technical limits are met and quality of supply is guaranteed for customers.

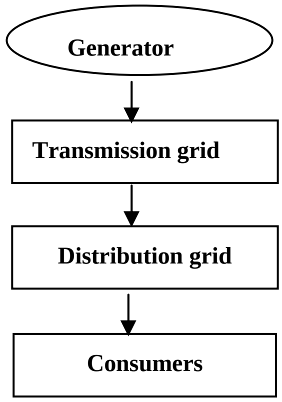
When connecting any new electricity generation plants to the distribution grid, the “strength” of the distribution grid near to the location of the generation plant must be known. One way of defining the grid “strength” is to determine the fault level of the grid. The fault level (or short-circuit level) is a measure of the current occurring when a fault, e.g. a short circuit, occurs on the grid. A grid with a ‘high fault level’ is generally a multi-interconnected grid in an area like a city centre or large industrial area, whereas a grid with a ‘low fault level’ is generally a long rural line. In general, the larger the value of the network voltage is, the stronger the system. In general, many distribution grids at 10 to 30 kV are “weak” and have a low fault level. Such low-voltage lines are most abundant in rural or remote areas; areas where increasingly significant amounts of distributed and renewable electricity (DG/RES-E)[3] generation is expected to be integration into the distribution system. Therefore, a variety of upcoming technical, economical and regulatory challenges are expected in almost all centralised electricity systems worldwide in the future in order to enable distribution grids to absorb large amounts of DG/RES-E generation.

1.2 Increasing Relevance of Distributed Generation

The paradigm of unidirectional power flows in centralised electricity systems from the central power plant to the grid infrastructure and finally to the customer (see Figure 1a (left)) is increasingly changing (see e.g. Auer et al (2005)). The connection of increasing amounts on distributed and renewable electricity generation on the medium voltage (MV) and low voltage (LV) distribution grids producing closer at the consumers increasingly displaces also power flows from the transmission systems and, therefore, requires changes to the traditional mode of operation for distribution systems (see Figure 1b (right)).

Moreover, the distribution grids are increasingly expected to move from their traditional role as passive networks – responsible for ensuring that the distribution network meets reliability targets and connects passive customers – to actively managed elements in the entire electricity system. This has at least the following two meanings: (i) active as in managing ancillary services on distribution grid level and (ii) active in taking a more pro-active role in stimulating integration of DG/RES-E generation to reduce network investments and losses, encouraging demand side management, etc. Further attributes of actively managed distribution grids in this context are presented in the subsequent section 1.3.

[3] Distributed and renewable electricity generation (DG/RES-E) includes several kinds of renewable electricity generation plants (like wind, biomass, biogas, landfill gas, small hydro, etc.), cogeneration or combined heat and power plants (CHP and micro-CHP), small stand-alone fossil fuelled generators (e.g. diesel and gas engines), fuel cells and domestic or small commercial photovoltaic solar generation and others.



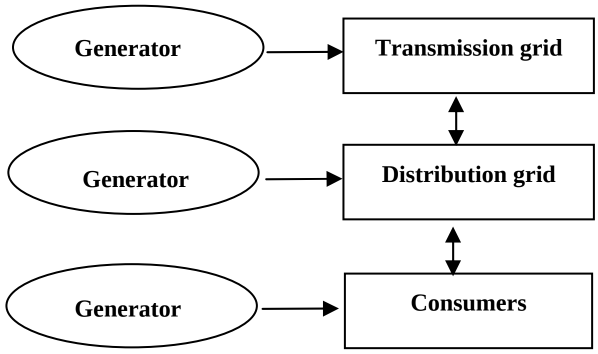


Figure 1a. Centralised electricity system Figure 1b. Decentralised electricity system

Mainly due to the lack of scale efficiency (i.e. lack of economies of scale), at present many DG/RES-E generation technologies can not compete with centralised conventional power plants. Therefore, almost all of them are subjected to environmentally motivated promotion policies to significantly accelerate electricity market integration. However, one of the biggest advantages of DG/RES-E generation technologies is that primary energy can be used more efficiently through the combined generation of heat and power and/or the use of renewable energy sources without any kind of "fuel" (e.g. wind, solar and hydro-power). Moreover, there are a variety of additional benefits for electricity systems in case of high penetration of DG/RES-E generation. A selection of them is given below (see e.g. Auer (2007d) in detail):

- <u>Reduced losses and deferred network investments</u>: DG/RES-E generation has the advantage (relative to centralised electricity generation) of being more closely located to customer demands. This proximity can help reduce distribution and transmission losses, reduce constraints on lines that are at (or near) capacity limits, and potentially defer the need for new investments in congested parts of the transmission or distribution network.

- <u>Enhanced security of supply:</u> Increasing shares of DG/RES-E generation have the potential to enhance security of supply. Because DG/RES-E generation is located closer to centres of demand, and is by definition more dispersed than centralised generation, the effects of any unexpected outage of a single decentralised generation plant or constraint on a transmission line may be reduced.

- <u>Meeting demand growth:</u> Related to the security of supply attribute, DG/RES-E generation also significantly contributes to meet demand growth in the future.

- <u>Environmental benefits:</u> To the extent that DG/RES-E generation can use primary energy more efficiently through combined heat and power generation or is based exclusively on renewable generation technologies, environmental and climate change objectives can be met more easily compared to a centralised conventional power plant portfolio.

- Market entry and competition: DG/RES-E generation projects are usually smaller and, therefore, barriers to entry for new players in the generation market are supposed to be lower (compared to centralised electricity markets). In general, as more players enter the generation market, competition shall increase, with a consequential benefit in downward pressure on wholesale electricity market prices.

The implementation of increasing shares of DG/RES-E generation into the existing electricity systems is also accompanied by additional challenges. Moreover, if regulatory frameworks remain unchanged, this may negatively affect distribution grid operators.[4] Due to the fact that DG/RES-E generation units are generally located closer to demand than central power plants, increasing DG/RES-E penetration may also result in decreasing revenues for distribution grid operators, as less electricity transport is needed to deliver dispersed generation to customers. Next to decreasing revenues, the increasing penetration of DG/RES-E generation may also lead to increasing cost. DG/RES-E generation units are mostly connected to the distribution network at low voltage levels, i.e. sites that were originally not meant to connect electricity generation facilities. This new situation can create also problems for the distribution networks in terms of stability and power quality. A selection of upcoming technical challenges in this context is as follows (for details see e.g. Auer et al (2005)):

- Dispersed DG/RES-E generation can change from full generation to no generation; the distribution grid must cope with this situation without reducing system stability and quality of supply.

- The direction and quantity of real (active) and reactive power flows changes, which affects operation of distribution grid control and protection equipment; power controllers at the DG/RES-E generator can improve both active and reactive power characteristics.

- Design and operation practices of distribution grids are no longer adequate and have to be fundamentally changed.

1.3 Impact of Distributed Generation on the Liberalised Electricity Market

In liberalised electricity markets, previously vertically integration electricity supply systems are split into clearly defined and separately accounted entities such as electricity generation, high-voltage transmission, low-voltage distribution and customer supply. Moreover, besides the separation of the different elements of the physical infrastructure of the electricity supply chain also commodity markets have been implemented for wholesale electricity trade and retail electricity supply,

[4] Comprehensive recommendations for amendments of the regulatory framework in electricity grid regulation (i.e. setting incentives for grid operators to absorb large amounts of DG/RES-E generation) are discussed in subsequent sections.

representing further essential ingredients of competitive electricity markets, see Figure 2a.

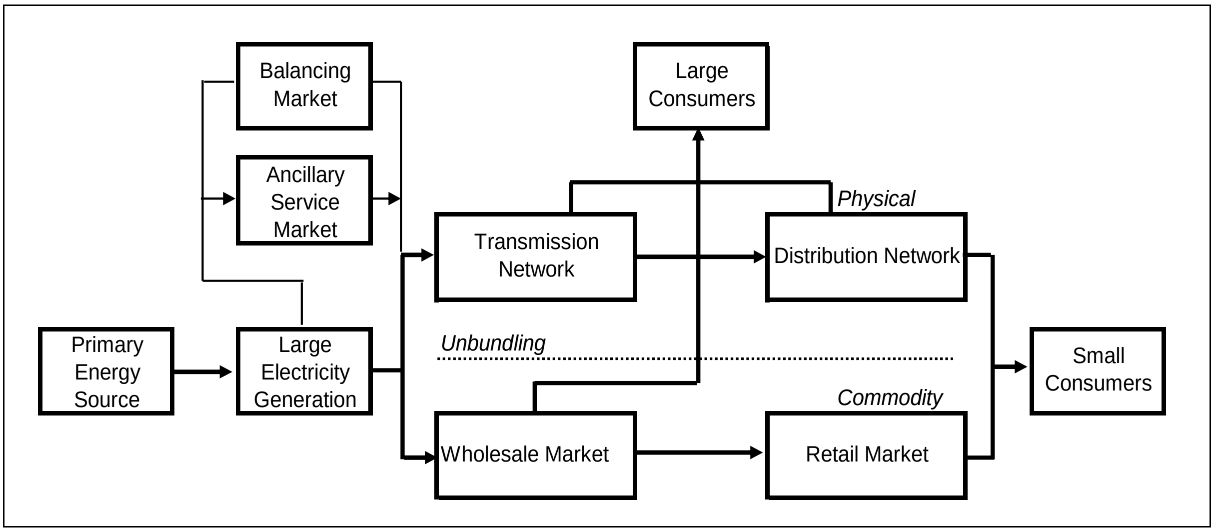


Figure 2a. Conventional centralised electricity supply systems in a liberalised market. Source: van Werven/Scheepers (2005).

Whereas Figure 2a presents the major elements of a conventional centralised electricity supply system in a liberalised electricity market, Figure 2b includes the most important additional components, connections, relationships and interdependences in case of significant penetration of dispersed DG/RES-E electricity generation.

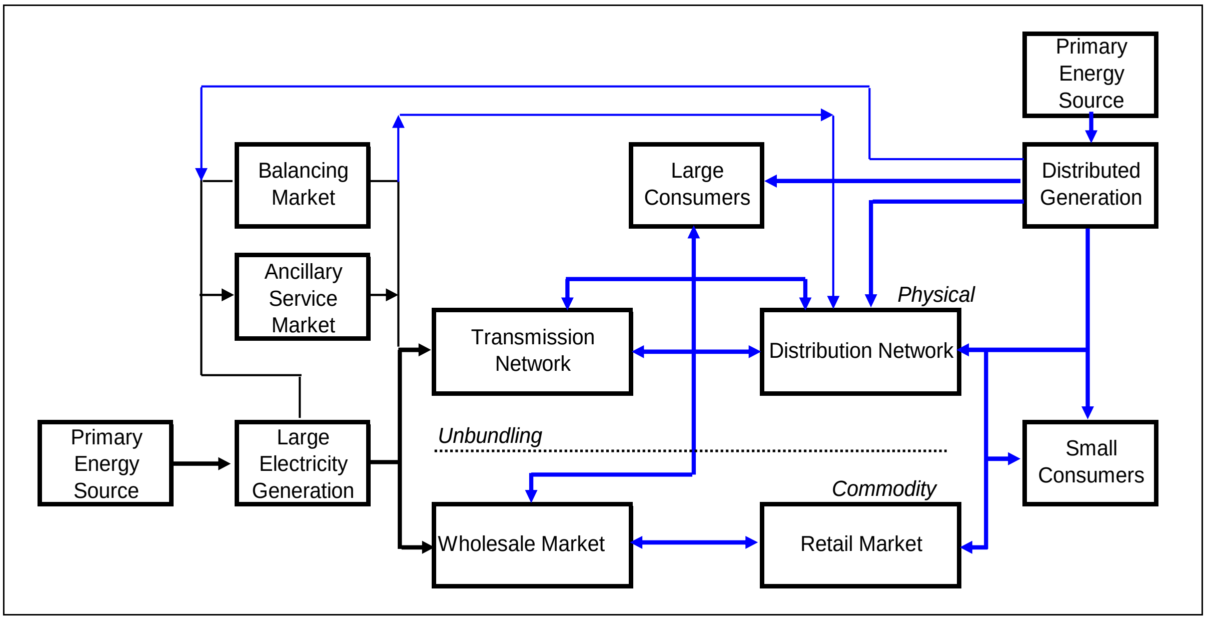


Figure 2b. Future electricity supply system with high penetration of DG/RES generation in a liberalised market. Source: van Werven/Scheepers (2005).

1. Flexibility/Modularity of Distributed Generation

Figure 2b demonstrates that DG/RES-E generation can complement the existing centralised electricity supply infrastructure, overcome network congestion, provide ancillary services and improve overall system reliability. Furthermore, the overall modularity of DG/RES-E generation offers enhanced flexibility in electricity system planning through the possibility to defer investments in centralised electricity generation facilities, as well as transmission grid reinforcements and extensions. On the other hand, the integration of DG/RES-E generation units with intermittent generation characteristics (e.g. wind and in some cases also combined heat and power generation (CHP)) pose additional challenges to system balancing. Additionally, an increased level of DG/RES-E penetration requires a transition from centralised control and system balancing by few market actors to a control system that allows and coordinates decentralised decision making by many actors (for details in this context see van Werven/Scheepers (2005)).

2. Balancing Market

In the past, the transmission system operator (TSO) exclusively has been responsible to maintain the short and medium-term balance of electricity generation and demand.[5] For this purpose, ex-ante forecasts have been submitted by the different market players. Deviations between electricity generation and demand have been visible in online system operation of the TSO as an exchange of electricity with neighbouring control areas. The TSO automatically compensated any imbalance by adjusting generation capacity upwards or making use of demand response (both in case of a shortage) or by adjusting generation capacity downwards (in case of a surplus). For this balancing purpose, a TSO bilaterally contracted balancing power from large power producers (e.g. by annual or monthly contracts) and socialised the corresponding cost in the transmission tariffs.

A more elegant and efficient way of balancing the electricity system is the establishment of a separate balancing market, which is controlled by the TSO (for details see e.g. van Werven/ Scheepers (2005)). This means that the TSO is the single buyer on this market, where mainly large power producers, DG/RES-E generators (in particular large CHP-units) and energy suppliers (demand response by their customers) contribute. In case of shortages of the system, the TSO corrects this by buying the lowest priced offer in the balancing market. The TSO then charges the energy supplier(s) that caused the imbalance. In case of a surplus of electricity generation, the TSO accepts and receives the highest bid in the balancing market for adjusting generating units downwards.[6] Also in this case the energy supplier(s) pay the TSO an imbalance charges.

[5] An example of long-term responsibility, which is also an issue for TSOs, is maintenance planning of centralised electricity generation capacities. The very long-term investment in electricity generation capacity is another element of responsibility which is left to the price signals on the wholesale electricity markets.

[6] Usually, generators have to pay the TSO for adjusting generation units downwards during a surplus in the total system. But it is possible that a negative price for electricity develops; in this case the generator receives money for producing less electricity (adjusting generation units downwards).

3. Ancillary Service Market

Besides the establishment of separate balancing markets, ancillary services are another relevant issue in case of significant penetration of DG/RES-E generation. However, ancillary services have very different characteristics. Therefore, it is not target-aimed of creating a separate ancillary services market. Ancillary services are all services necessary for the operation of a transmission and distribution system. They comprise compensation for energy losses, frequency control (automated, local fast control and coordinated slow control), voltage and power flow control (reactive power, active power, and regulation devices), and restoration of supply (black start, temporary island operation). These services are provided by generators and the system operators and are required to provide system reliability and power quality.

An important distinction has to be made between distribution networks and the transmission network. In general, DG/RES-E generators can offer local ancillary services to the distribution grid operators. Moreover, there often exist local needs for ancillary services (e.g. voltage support (active power) or reactive power) that only can be fulfilled locally unless reinforcements or extensions of the local distribution network infrastructure enable “imports” of ancillary services from the transmission grid operators.[7]

[7] Therefore, deploying DG/RES-E generation facilities on the right sites can be an alternative for investments into grid reinforcements or extensions. Thus some ancillary services can be offered by DG/RES-E generators directly to the distribution system operator, whereas other ancillary services like frequency control (needed for the operation of the transmission systems) only can be offered by large centralised conventional power plants. However, at present very few implemented DG/RES-E generation units are equipped with the infrastructure necessary to provide ancillary services. This is supposed to change in the future with increasing shares of DG/RES-E generation in electricity supply systems.

2. The Grid Connection/Access Boundary Question

2.1 The Role of Unbundling

When integrating significant amounts of DG/RES-E generation technologies into the existing electricity systems, the grid connection/access boundary question is still one of the most controversial issues in practise. Moreover, besides the connection of DG/RES-E facilities to the existing grid infrastructure also grid reinforcement and extension measures caused by large-scale DG/RES-E system integration raise a set of new questions, e.g. where to allocate the corresponding extra cost and how to socialise them. In any case, in an intermeshed grid infrastructure the allocation of grid reinforcement and extension measures and corresponding cost to a newly integrated DG/RES-E generation facility is ambiguous,[8] see Figure 3.

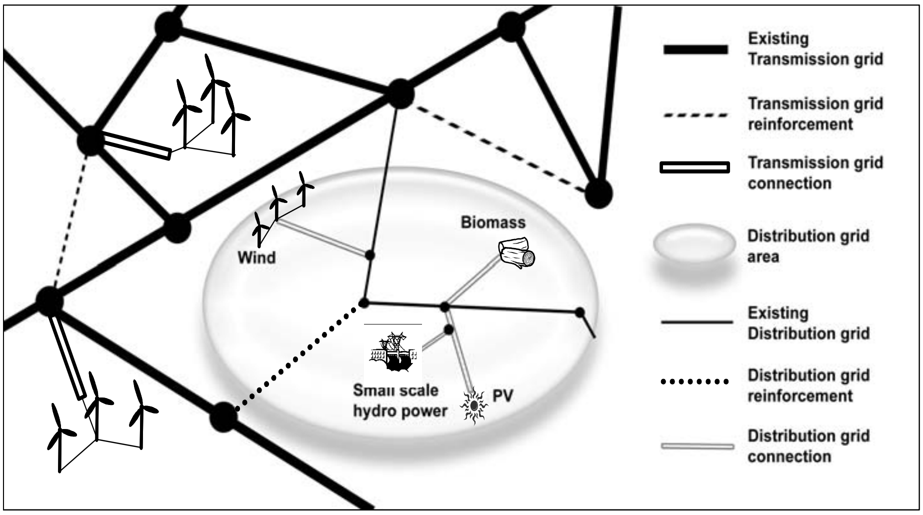


Figure 3. Grid connections and grid reinforcements caused by large-scale DG/RES-E integration. Source: Auer (2006).

The core problem in this context is that any changes in an intermeshed grid infrastructure (e.g. also disconnection of a large industrial customer) will change the load flows in an electricity system. Therefore, the status quo of load flows in an electricity system is also just a snapshot of the existing randomization of generation and load centres. Moreover, the status quo as well as changes of load flows have a variety of dimensions, as there are e.g. changes in the geographic distribution of generation and load centres, bottlenecks in peaking periods or commercial power trading activities. Therefore, the allocation of load flow changes and, subsequently, grid reinforcement and extension measures to the integration of a single new DG/RES-E generation facility is at least questionable.

[8] Not least due to the fact that several other market participants (especially power traders) also benefit in their business segments from additional transmission capacities.

2.2 Different Grid Connection Boundaries for DG/RES-E Generation Facilities

Textbooks in economic theory (e.g. Averch/Johnson (1962), Baumol/Bradford (1970), Baumol et al (1983), etc.) would expect to allocate both DG/RES-E grid connection cost and grid reinforcement and extension cost to the grid infrastructure and to socialize these cost through the transmission and distribution tariffs[9] (and not to include either of these two cost components to the total DG/RES-E project cost). In practice, however, several grid-related cost components (at least the grid connection cost) are still allocated to the long-run marginal generation cost of the DG/RES-E power plant, especially as far as DG/RES-E grid connections to the distribution grid are concerned. In general, the following grid connection boundaries between the DG/RES-E generation facilities and the grid infrastructure are possible (see Figures 4, 5a and 5b in detail):

- "Deep" Integration: Based on this approach, the DG/RES-E developer bears several extra grid-infrastructure related DG/RES-E integration cost (i.e. grid connection as well as grid reinforcement/extension cost) and includes them into the total DG/RES-E project cost.

- "Shallow" Integration: The shallow grid integration approach usually characterises the situation where the DG/RES-E developer bears the grid connection cost, but not the grid reinforcement/extension cost (they are socialised in the grid tariffs).

- "Super-Shallow" Integration: This is supposed to be the most convenient approach for the DG/RES-E developers since neither the grid connection cost nor the grid reinforcement/ extension cost are borne by them.

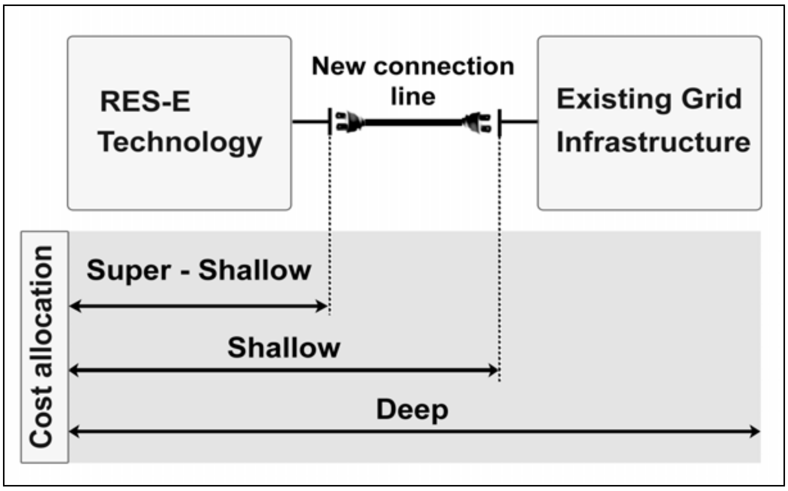


Figure 4. Different connection boundaries between the DG/RES-E power plant and grid infrastructure. Source: Auer et al (2007b).

In practise, however, there mainly exist hybrid approaches incorporating elements of both "deep" and "shallow" DG/RES-E grid integration. This means in particular that

[9] In principle, there exist both options: (i) socialisation within a supply area of a grid operator or (ii) socialisation across the whole country (i.e. covering also several other grid operators).

usually parts of the grid reinforcement and grid extension cost are allocated to the newly connected DG/RES-E generation facility (i.e. some kind of "deep" grid integration free) and remaining parts of the deep cost are socialised in the grid tariffs. In addition, the entire grid connection cost are borne by the DG/RES-E developer and allocated to the long-run marginal generation cost in the hybrid model. Table 1 summarizes the status quo of the implemented cost allocation policies for DG/RES-E grid integration in the 'old' EU15 Member States in 2007. For detailed analyses and comparisons of currently existing electricity grid regulation practises and the corresponding impact on DG/RES-E grid and system integration in selected EU Member States it is referred to the Appendix.

Table 1. DG/RES-E grid integration and cost allocation policy in the 'old' EU15 Member States in 2007. Source: Auer (2006b; updated).

	RES-E grid integration cost allocation scheme	Max. grid connection cost	Cost transparency
Austria	Deep	10% of investment	Low
Belgium	Hybrid	5-10% of investment	High
Denmark	Shallow	5-10% of investment	High
Finland	No standardised approach	-	Medium
France	Hybrid	10-20% of investment	Medium
Germany	Hybrid	-	Low
Greece	Hybrid	-	Low
Ireland	Deep	3-8% of investment	High
Italy	Deep	-	Low
Luxembourg	Deep	-	Low
Netherlands	Hybrid	-	High
Portugal	Deep	15% of investment	Medium
Spain	Deep	-	Low
Sweden	Deep	10% of investment	Low
UK	Hybrid	8-12% of investment	High

In some EU Member States the existing pattern for allocating the DG/RES-E grid integration cost might change in the near future, not least due to the currently ongoing benchmarking and grid regulation exercises being conducted by national regulators. Although these regulatory procedures are driven to fulfil the basic unbundling principles of the different EC-Directives and the implementation of cost transparency in grid infrastructure charging rather than by DG/RES-E grid integration policies, finally the existing boundaries between the DG/RES-E power plant and the grid infrastructure may be shifted increasingly towards the DG/RES-E generation facilities, resulting at least in a "shallow" integration policy or even beyond.[10]

The "super-shallow" DG/RES-E grid integration policy finally fulfils almost all expectations of the theoretical considerations in economic theory. However, the

[10] Interestingly, in the past the demand site always has been treated differently (compared to the generation site) when defining the grid connection boundary of customers. According to economic theory there is no obvious reason to do so (see e.g. Jamasb et al (2005)). Demand customers traditionally have paid "shallow" connection charges – for assets specifically required for their connection – whilst distributed generators have been charged on a "deep" basis, i.e. the full cost of work arising from the connection including the costs of replacing equipment associated with protecting the network or also the provision of ancillary services. However, an increase in DG/RES-E grid integration in the future, especially at connections which may export and import electricity at different times, is expected to blur the established distinction between demand and generation connections thus fundamentally changing distribution grid operator's cost drivers. These new circumstances also lead to the conclusion that existing charging structures for DG/RES-E grid integration (still mainly "deep" and "hybrid" models; see Table 1) may no longer be appropriate.

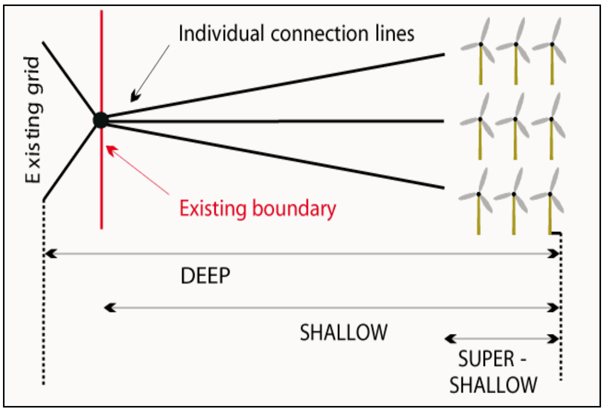
locational signal aspect may get increasingly lost in case of this DG/RES-E grid integration policy. But this is an important dimension for a sustainable and cost minimizing integration of DG/RES-E generation facilities into existing electricity systems, especially as far as small generation units into distribution grids are addressed (see also the discussion about the importance to select most fitting sites for DG/RES-E grid connection in section 1.3).

Therefore, the “super-shallow” grid integration policy option has been developed in recent years mainly for large-scale offshore-wind (but also onshore-wind) integration into the exiting transmission grids rather than for integration of remaining DG/RES-E generation technologies on distribution grid level. Moreover, when considering large-scale offshore wind integration into transmission grids, usually the economic situation presented in equation 1 exists:

If $C_{Transmission,i}$ are the offshore transmission grid connection cost of an individual wind farm *i* in case of separate grid connection (see Figure 5a (left)) and $C_{Transmission,common}$ the common offshore transmission grid connection cost of all wind farms (c_i is the individual short distribution grid component of wind farm *i*; see Figure 5b (right)) the following relationship exists:

$$C_{Transmission,common} + \sum_{i=1}^{n} c_i < \sum_{i=1}^{n} C_{Transmission,i} \qquad \text{(Equation 1)}$$

Equation 1 demonstrates that cumulated transmission grid connection cost of the individual offshore wind farms (Figure 5a (left)) are higher than the common transmission grid connection cost (plus individual short distribution grid components) of a collective of several offshore wind farms (Figure 5b (right)).



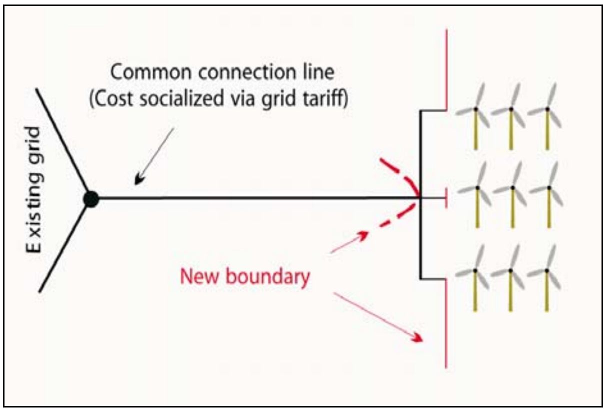


Figure 5a (left). Separate offshore grid connection of each individual offshore wind farm and indication of different boundaries for different integration policies. Source: Auer (2006).

Figure 5b (right). Common offshore grid connection of several offshore wind farms and shift of new connection boundaries towards offshore wind farms. Source: Auer (2006).

2.3 The Locational Signal Aspect in the Context of DG/RES-E Integration

The overall objective of different cost allocation and DG/RES-E integration charging policies is to guide efficient expansion and use of the electricity grids (distribution grids in particular), on the one hand, and efficient management of the assets connected to the grid infrastructure representing both generation and load facilities, on the other hand. Whereas economic theory presents clear approaches and procedures for optimal DG/RES-E grid integration into existing electricity systems,[11] circumstances in practise are far more complex and accompanied by a variety of uncertainties, imperfections and problems. A selection of these critical issues of the different DG/RES-E integration policies in practise is discussed in subsequent paragraphs.

1. "Deep" Integration: Ideal versus Real World

In general, the deep DG/RES-E integration approach has the advantage of providing strong locational signals for new entrants. However, this approach – having been traditionally adopted by distribution grid operators in the past – is far from uncritical. In practise there exist at least the following vexing challenges (see also Jamasb et al (2005), DTI (2006), Auer (2006), Vogel (2008), Barth et al (2008)):

- Although deep DG/RES-E integration is characterised by favourable locational signals to new entrants, the computation of proper deep connection cost (and, subsequently, connection charges to DG/RES-E generators) is very difficult because it is impossible to correctly foresee the future set of entrants on the distribution grid, their needs (e.g. connection capacity) and the values they place on each location.[12] Therefore, a best guess has to be made when calculating location-specific deep connection charges, trading-off the benefits of larger increments against the risk of over-sizing connection capacity and hence prescribing overcharges for connection of DG/RES-E generators.

- Furthermore, assuming the case that the connection assets of a specific location are shared by more than one DG/RES-E generator, the cost would also be shared, but as the assets would be quasi-public goods, efficient charges would not necessarily be the same for several new entrants at the same location if their willingness to pay is different.

- In almost all cases the situation described above is getting even more complex, since DG/RES-E connection inquires are rather sequential in time than simultaneous. For sequential connection inquiries the first mover problem at a specific location is inherent, i.e. the critical question arises whether or not the first

[11] In economic theory, the general principle underlying efficient DG/RES-E grid integration charging is that charges should reflect the different marginal cost and benefits to the electricity system at each node of DG/RES-E connection.

[12] Only in theory the distribution grid operator can optimally plan the distribution network and specify the location of each new entrant by setting corresponding location-specific and entrant-specific deep connection charges. In this ideal world the total collected connection charges from each entrant at each location would exactly add up to the total connection cost of several new DG/RES-E generators on distribution grid level.

entrant shall be charged the full cost and encourage subsequent entrants to rebate some fraction (either by granting the right to the first entrant to charge successors, or calculating a charge for successors by the distribution grid operator and rebating it to the first entrant).[13]

- Last but not least, there exists a strong concern about the deterrent effects on large-scale DG/RES-E deployment in case of deep integration charging policies. Moreover, this approach completely violates the basic unbundling principle and, therefore, also undermines the legal framework of the EC-Directives of the European Commission trying to implement a common internal European electricity market.

2. "Shallow" Integration: Ideal versus Real World

Although deep DG/RES-E integration policies provide strong locational signals, recognition of the disadvantages of this approach has favoured rather hybrid mechanism (incorporating elements of both deep and shallow charging) in majority of EU Member States in recent years (see Table 1 in detail). Moreover, not least driven by the expectations to fulfil the basic unbundling principles of the EC-Directives further amendments towards shallow integration policies are expected in the context of DG/RES-E grid integration in the near future.

Shallow DG/RES-E integration policies aim to limit the connection assets attributed to the entrant (e.g. up to the next voltage level). However, if it is to signal location for DG/RES-E integration into the existing distribution grid efficiently, then a shallow integration charge has to incorporate also location specific cost elements. Otherwise there will be a tension between the entrant wishing to connect to the nearest point of the distribution grid from his most favourable location, on the one hand, and the distribution grid operator favouring connection at points which minimise total network cost, on the other hand. This could lead the distribution grid operator delaying or otherwise obstructing entry at some points on the distribution grid if it is not clear which points were in fact cost-minimising. The ultimate peculiarity of a locational signal in the shallow integration approach therefore is a rejection of a DG/RES-E connection inquiry.

Compared to the deep integration approach, shallow integration charging has at least the following further advantages (see also Jamasb et al (2005), DTI (2006), Auer (2006), Vogel (2008), Barth et al (2008)):

[13] In general, DG/RES-E generators and, therefore, also the first entrant are likely to be less well-informed than the distribution grid operator about the connection capacity needed and corresponding cost. Moreover, the first entrant usually is also not in a financial position to raise the capital to pay for more than its own grid connection. Therefore, from the first mover's point-of-view it is an advantage if distribution grid operators charge for the cost of the connection in proportion to the use made of the different entrants. However, in this ideal case the distribution grid operator faces the following risks: (i) subsequent entrants must arrive as predicted, (ii) the correct connection capacities must be chosen and (iii) the willingness to pay for connection of subsequent entrants must be similar.

- Shallow DG/RES-E integration cost and corresponding charges are presumably easier to define than those for the deep integration approach.

- The first mover problem disappears since the first entrant is expected to be charged only for the cost of the connection in proportion to the use made of it. Moreover, from the distribution grid operator's point-of-view the risk of cost remuneration in case of over-sizing connection capacity (e.g. for providing the basis for synergies for later DG/RES-E connections at the same location) disappears since grid reinforcement and upgrading cost are socialised in the grid tariffs and, therefore, are directly borne by the network users.

- Previous arguments lead to the conclusion that barriers for entry are low in case of shallow integration policies, providing favourable framework conditions for large-scale DG/RES-E deployment on distribution grid level. Moreover, shallow DG/RES-E integration is supposed to be more transparent and acceptable for several parties involved.

- In general, total DG/RES-E integration cost are lower in case of shallow integration policies. This is due to the fact that financing cost are likely to be higher for DG/RES-E developers than for regulated distribution grid operators.[14] Moreover, cost components for grid reinforcements and upgrades – being allocated to the distribution grid operator and socialised in the grid tariffs of the network users in case of shallow integration – are not included into the financing cost of the DG/RES-E developer to be connected (where a higher risk premium would be incorporated compared to the socialisation in the grid tariffs). This provides a strong argument against deep integration charging.

- Finally, the shallow DG/RES-E integration approach goes even more in line with the basic unbundling principles of the EC-Directives than the deep approach. Moreover, due to clear separation of the assets of DG/RES-E generation facilities, on the one hand, and the grid infrastructure, on the other hand, extra grid infrastructure cost (grid reinforce-ments, upgrades and extensions) caused by large-scale DG/RES-E integration can even better be incorporated directly into "forward-looking" grid regulation models where an extra term can be foreseen to socialise these kind of extra cost.[15]

[14] Mainly due to higher risk premiums and shorter depreciation periods the financing cost are likely to be higher for DG/RES-E developers than for regulated distribution grid operators. For example, DG/RES-E generation facilities are depreciated in time horizons of 10-15 years whereas regulated grid operators depreciate their grid infrastructure assets in 40-50 years.

[15] Forward-looking grid regulation models incorporating also extra grid-infrastructure related cost caused by large-scale DG/RES-E integration are comprehensively discussed in subsequent sections 3 and 4.

3. Problem of Asset Stranding for Distribution Grid Operators

3.1 Overview on Cost Drivers for Distribution Grid Operators

The previous section 2 has comprehensively analyzed the different cost allocation and DG/RES-E grid integration policies mainly from the DG/RES-E developer's point-of-view. However, when considering large-scale DG/RES-E integration also the distribution grid operator is confronted with much more financial risk as recognized up to now (for details see e.g. Auer (2007d)):

- On the one hand, currently implemented grid regulation models apply a strong downward pressure on the distribution grid operator's cost and, subsequently, also distribution grid tariffs. At present, this regulatory environment adversely affects any investment initiatives into the electricity grid infrastructure, not only those foreseen to provide a level playing field for large-scale DG/RES-E integration and other innovations like so-called "smart grid" concepts. The basic principles of currently implemented grid regulation procedures and the corresponding interactions with DG/RES-E grid and system integration are briefly summarized and critically discussed in section 3.2 below.

- On the other hand, electricity grids are capital-intensive infrastructure elements being characterized by grid assets' life-times over many decades. Therefore, long-term investments into the grid infrastructure expect stable regulatory conditions. Moreover, once investments are made they are effectively sunk and, therefore, grid assets are vulnerable to changes in regulatory conditions which could prevent or hinder cost recovery. Therefore, distribution grid operators are extremely reluctant to enable large-scale integration of DG/RES-E generation facilities into their distribution grids, unless the corresponding extra cost drivers in this context are not understood, quantified and – most importantly – cost recovery is guaranteed based on innovative, forward-looking grid regulation models.

Figure 6 below presents the two categories of cost pressure forces regulated distribution grid operators have to cope with at present: (i) cost cutting incentives according to the currently implemented incentive regulation models (left); (ii) a variety of currently unconsidered extra cost drivers in case of large-scale DG/RES-E grid and system integration on distribution level (right).

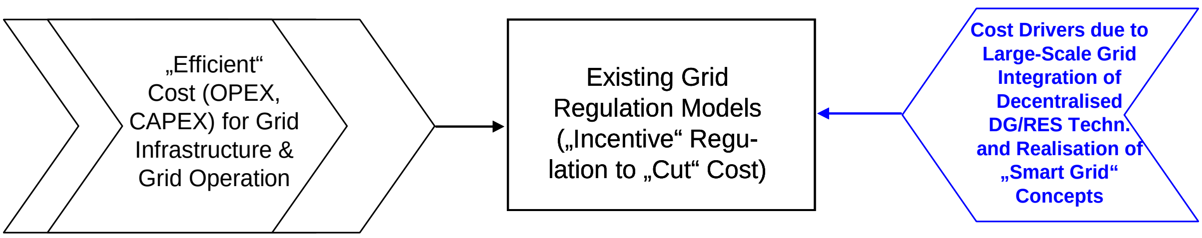


Figure 6. Problem of asset stranding in existing grid regulation models due to unconsidered cost drivers caused by large-scale DG/RES-E integration. Source: Auer (2007d).

3.2 Cost Drivers due to Incentive Regulation

The overall objective of newly implemented incentive regulation models in recently years in many EU Member States is to provide the regulated electricity grid operators with incentives to improve their investment and operating efficiency (taking into consideration also exogenous and structural constraints) and to ensure that network users benefit from these efficiency improvements. In order to do so, a couple of individual steps are necessary in practise, see Figure 7.

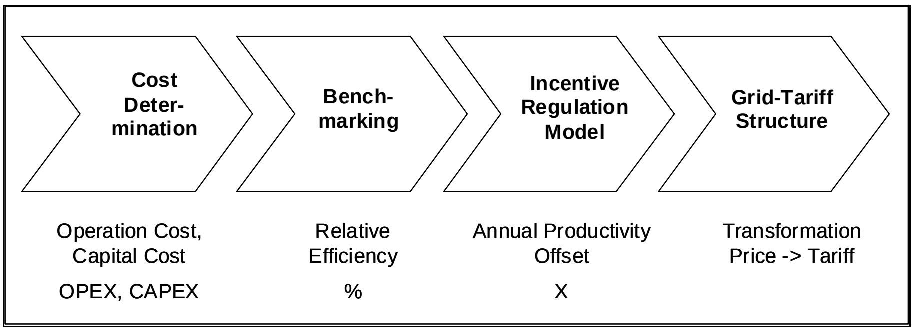


Figure 7. Overview of the different steps of a grid regulation process.

The different steps of a grid regulation process in practise can be summarized as follows:

- Step 1: The determination of the actual cost structure and the different cost categories of a firm (mainly capital and operation cost) is a precondition in the grid regulation process in order to be able to compare the status quo of a regulated firm with predefined exogenous and endogenous benchmarks. Details of step 1 are presented in box 1 below.

- Step 2: The cost-benchmarking exercise itself is the most vexing and also criticised part of the grid regulation process in practise. In recent years, regulators have adopted and applied a variety of benchmarking methods and techniques to better capture also the unique characteristics of electricity grids. However, there still exists a controversial discussion on the applicability of several of these benchmarking methods whether or not they are able to describe complexity of reality sufficiently. Moreover, the description of the economic performance of a grid operator by a single efficiency parameter is denoted hazardous anyway. For details on this second step see box 2 below.

- Step 3: In the next step, the benchmarking result – i.e. the relative efficiency of the investigated firm compared to remaining firms in the sample – is implemented into the “RPI-X” approach of one of the incentive regulation models. There exist different philosophies to implement the productivity offset X (i.e. the efficiency improvement factor in the upcoming regulatory period) into the incentive regulation models. Details in this context are presented in box 3 below.

- Step 4: And finally, authorized (aggregated) price levels have to be transformed into different grid tariffs for different customer groups. In practise, there exists some degree of freedom in the design of the different grid tariffs and tariff structures for grid operators.

In the following, the different steps of a grid regulation process summarized above are discussed in detail in the different boxes 1-3.

Box 1: Determination and Allocation of Eligible Cost

The major cost categories in electricity grid operation are capital cost, on the one hand, and operation and maintenance cost, on the other hand. Whereas capital cost mainly describe depreciation and the rate-of-return on capital invested into assets of the grid infrastructure (cables, wires, transformer stations, etc.), operation and maintenance cost cover the day-to-day cost of delivering electricity and providing grid operation services including maintenance, planning, controlling, metering, billing, and taxes. However, the existence of a potential for significant trade-offs between capital cost and operation and maintenance cost must also be recognised. The trade-offs may reflect e.g. capital investment in the undergrounding of lines that can reduce ongoing operation cost. Moreover, the trade-offs can also arise from accounting methods and conventions that allow the capitalisation of operation cost. Moreover, practical experience in benchmarking the cost-efficiency of electricity grid operators has shown that the economic-performance of a firm is very sensitive to the inclusion of capital cost in the comparison. On the contrary, by omitting capital cost as an input, cost-benchmarking takes no account of such trade-offs mentioned above. Then, if a grid operator is able to reduce its operation cost simply by making such a trade-off, its efficiency score can improve for entirely spurious reasons.

In regulatory practise, furthermore, it is widely accepted that only parts of the capital and operation and maintenance cost can be controlled by the regulated grid operator, the rest being exogenous. Therefore, regulators have chosen to benchmark regulated grid operators only on the cost that their managers can control, known as controllable cost. However, the definition of controllable cost – and the separation from non-controllable cost – is far from straightforward (see e.g. Fillipini/Wild (2001)). In particular, the definition of controllable cost is problematic when dealing with capital cost. A substantial part of capital cost has been incurred many years (decades) in the past and under significantly different economic and regulatory circumstances. It is difficult to assess in what sense these capital cost are controllable for the management of a regulated grid operator. Constructing a comparable measure of capital cost (i.e. assuming that firms are placed on an even ground) is also particularly difficult if grid operators use different accounting methods and conventions when revaluing and depreciating their assets. However, capital cost accounting issues have largely been ignored in literature on incentive regulation in the past. Although it may have been of limited concern initially, in practise any well functioning regulatory system needs to adopt good mandatory accounting rules, reporting requirements for different performance dimensions (cost, outputs, prices, etc.). They must, furthermore, enforce auditing and monitoring protocols to ensure that the uncertainties in determining the regulated firm's performance can be minimized.

Box 2: Benchmarking of Eligible Cost

The major objective of several incentive regulation methods (see box 3 in detail) is to improve economic efficiency of electricity grid operators by rewarding good performance while the actual performance is measured relative to some predefined benchmarks. Benchmarking methods describe the provision of the portfolio of outputs and services of an electricity grid operator by an input-output model (“black-box”), where capital and labour are assumed to be the major inputs. The major outputs and services of an electricity grid operator are the transportation and delivery of electricity at numerous connection points around the network based on predefined service quality and security of supply levels.

The characteristics of transporting and delivering electricity represent critical dimensions of the outputs and services provided by the electricity grid operator. These characteristics include the *quantity*, *location* and *quality* of electricity delivered (see e.g. Nera (1999)). Each of these measures of outputs and services deserves careful consideration. Moreover, the satisfactory provision of them causes cost drivers on the input site. The factors determining the cost drivers are (see Figure 8):

- direct outputs and services of the electricity grid operator like number of customers supplied, peak load served, amount of electricity delivered, number and duration of supply interruptions caused, etc. and
- exogenous structural and environmental factors outside the control of the grid operator’s management as there are e.g. geographic distribution of customers, topology of the supply area, climate conditions, etc.

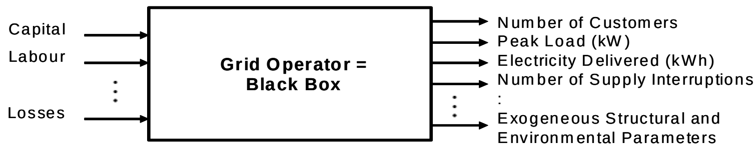


Figure 8. The grid operator as a simple Input-Output model

However, the distinction between direct output factors and structural as well as environmental factors is not always clear (for details in this context see e.g. Fillipini/Wild (2001)).[16]

According to Figure 8, almost all benchmarking techniques attempt to explain the grid operator’s cost by establishing a relationship between input cost (mainly capital, labour, losses) and a portfolio of outputs and services (i.e. cost drivers). The explained cost is used to define a so-called “efficiency frontier” and the unexplained cost, furthermore, is attributed to inefficiency, with an allowance in some cases for measurement errors.[17] In regulatory practise, there exist mainly the following different approaches to calculating the efficient cost in the electricity grid operation sector (see Figure 9; for details in this context it is referred to Auer (2008)):

- multi-dimensional top-down approaches, where large aggregates of cost (e.g. total cost or operation cost) are benchmarked based on frontier-methods or mean/average-methods,
- one-dimensional bottom-up approaches, also referred to as process benchmarking, where individual cost items (for instance maintenance cost per substation or per km of underground cable, etc.) are benchmarked separately, and
- engineering based approaches like “reference networks”, which attempt to combine a detailed technical understanding of cost drivers with a measure of overall cost.

[16] Some exercises count network length as an output (“distance delivered”), whilst some regard network length as a proxy for measuring environmental factors (e.g. such as “customer dispersion”). Usually, this distinction is not important to the calculation, but it affects the way in which the results are explained and discussed.

[17] In any case, unexplained cost may be also the result of factors other than inefficiency and measurement errors. Among others there are e.g. missing explanatory factors or incorrect specification of the functional relation between the explanatory variables of the benchmarking model.

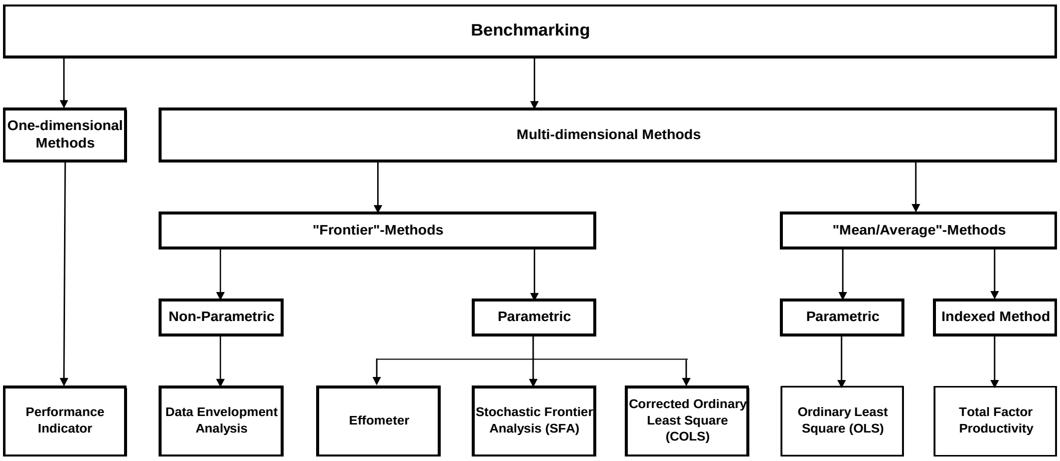


Figure 9. Overview of different benchmarking techniques. Source: Auer (2008)

Box 3: Implementation of Efficiency Goals into Grid Regulation Model

The previous box 2 summarizes the diversity of benchmarking methods used in practise to identify the cost-efficiency of electricity grid operators. Regardless of the benchmarking model used, the quantitative benchmarking result finally is a single factor determining cost-efficiency of a grid operator in comparison to a peer group of grid operators.

The next step in a grid regulation process (outlined at the beginning of section 3.2) is the translation of the benchmarking result into a so-called X-factor (productivity offset), having to be implemented into the “RPI-X” formula. Not least depending on the size of the sample of grid operators to be benchmarked, there exist different approaches to translate the benchmarking results into a productivity offset X. The most common approaches having been applied in regulatory practise so far are as follows:

- 1:1 translation of the benchmarking result (i.e. efficiency score) within a predefined bandwidth and implementation of the corresponding productivity offset X into the incentive regulation formula. Examples for this kind of implementation are the incentive regulation models applied in the Netherlands and UK.
- Clustering of different bandwidths of benchmarking results and linear conversion of the clustered benchmarking results into the corresponding productivity offsets X. The different clusters may be split into 5-10% intervals in efficiency scores. This kind of implementation of benchmarking results into the incentive regulation formula has been conducted in Norway and recently also in Austria.
- Individual bottom-up benchmarking of grid operators in case of a small number of grid operators to be investigated and individual implementation of the productivity offset into the incentive regulation formula. This approach has been implemented in Victoria/Australia in recent years where only five grid operators exist.

Besides the determination of the expected efficiency improvement (i.e. productivity offset X) within a regulatory period of typically 4-5 years, the annual schedule of efficiency improvement allotment (to meet overall X at the end of the regulatory period) is another essential implementation criterion for a successful incentive regulation model. In practise, two different approaches have been implemented up to now:

- Uniform distribution of annual efficiency improvement expectations. The advantage of this approach is that, on the one hand, the grid operator continuously can exploit its efficiency improvement potentials within a regulatory period and, on the other hand, also the price signals for the network users (i.e. grid tariff adjustments) are smooth.
- Disproportional efficiency improvement expectations at the beginning of a regulatory period and decreasing expectations in subsequent year. Although this regulatory policy might be an appropriate instrument for the regulator to demonstrate its power by putting pressure on the grid operators, it could trigger misleading expectations for networks users due to wrong signals for grid tariff adjustments in the medium- to long-term.

Eventually, besides the individual productivity offset X – also called catching-up factor and derived from cost-benchmarking of a grid operator within a sample of grid operators in a peer group – total productivity improvement expectations by a regulator within a regulatory period have an additional offset, the so-called "general X-factor". This general productivity improvement expectation of an industry – also called frontier-shift – is set by the regulator and has to be met by several grid operators regardless of the individual results in the benchmarking exercise.

Finally, the three most common incentive regulation models having implemented in practise are briefly summarized: price-cap, revenue-cap and yardstick regulation (for a comprehensive consideration of remaining incentive regulation models it is referred to Auer (2008)). These three regulation models are well-known approaches of modern incentive regulation.

- Under <u>price-cap regulation</u>, prices for regulated firms are set for long periods of time without regard to the firm's cost. Price caps are often indexed over time using the formula commonly known as the "RPI-X" formula (i.e. retail price index (RPI) minus productivity offset (X)). This formula sets prices each year as a function of the previous year's prices, inflation (retail price index; RPI) and a productivity offset (X), see e.g. Comnes et al (1995).

  $$P_t = P_{t-1} * (1 + RPI - X) \pm Z \qquad P = \sum p_i q_i$$

  where
  P_t..........authorized price-cap in year t
  P_{t-1}.......authorized price-cap in year (t-1)
  RPI.......annual inflation index (Retail Price Index)
  X...........productivity offset
  Z...........adjustments for unforeseen events beyond management's control
  p_i, q_i......price and quantity for market basket i (i.e. different customer categories i)[18]

  Price-cap regulation with infrequent rate cases (regulatory lag) creates an incentive for the grid operator to minimize cost.

- Similar to the price-cap regulation approach, under <u>revenue-cap regulation</u> the regulator caps the firm's allowed revenues with the external "RPI-X" index. As already mentioned above, this index is beyond firm's control but allows for changes in nominal prices (inflation) and productivity. Subject to the revenue-cap, the firm is permitted to maximise its profit margin, presumably by minimizing total cost. The formulation of a revenue-cap approach – including also an adjustment factor for annual changes in the number of customers – is as follows:

  $$\overline{R}_t = (\overline{R}_{t-1} + CGA * \Delta Cust) * (1 + RPI - X) \pm Z$$

  where
  $\overline{R}_t$ *..........authorized annual revenue in year t*
  $\overline{R}_{t-1}$ *......authorized annual revenue in year (t-1)*
  CGA......customer growth adjustment factor [€/Customer]
  Cust.....annual change in the number of customers
  RPI.........annual inflation index (Retail Price Index)
  X............productivity offset
  Z............adjustments for unforeseen events beyond management's control

  Although revenue-caps and price-caps create the same incentives to minimize cost, they differ significantly in terms of the incentives they provide for incremental outputs

[18] The price-cap usually is a "global" cap. This means, that the regulated firm has some degree of freedom to set the individual basket prices for the different customer groups.

(i.e. electricity delivered in case of electricity grid operators). The incentive to maximise outputs that exists under price-cap regulation does not exist with revenue-caps. Revenue-caps can create incentives for grid operators also to minimize outputs (e.g. by raising prices) as a way of reducing cost. Thus, revenue-caps (in electricity grid regulation) may be more appropriate to implement energy efficiency programmes or other demand side activities in the electricity sector in general.

- In the basic concept of yardstick regulation the performance of a firm is compared directly to the performance of similarly situated firms. Typically, firm's costs are compared to those of a peer group of firms. A simple yardstick regulation approach is based on both a firm's own cost and cost of a group of firms within a peer group (see e.g. Shleifer (1985)).

$$P_{i,t} = \alpha_i C_{i,t} + (1-\alpha_i) * \sum_{j=1}^{n} (f_j C_{j,t})$$

$P_{i,t}$..........authorized price-cap for firm i in period t
α_i...........share of own-firm cost information used of firm i (α_i=0 is pure Yardstick regulation)
$C_{i,t}$..........unit cost of firm i in period t
f_j............revenue or quantity weights for peer group firms j
$C_{j,t}$.........unit cost (or prices) for peer group firms j
n............number of firms in peer group

Yardstick regulation models use some kind of competitive benchmark and, therefore, do not need an explicit productivity adjustment. Moreover, yardstick regulation is of particular value when several firms in the sample have cost characteristics that are correlated with each other (see e.g. Armstrong et al (1994)). However, despite their theoretical attractiveness, yardstick indices in reality tend to be applicable only for supplemental measures than as the prime incentive regulation model. Reluctance to use yardstick regulation exclusively appears to be a result of the potential volatility of such measures, which leads firms to fear that these measures inaccurately reflect firm's cost.

The most frequently cited point of criticism of the application of yardstick regulation in the context of electricity grid infrastructures is that exogenous and environmental constraints in the different regional supply areas are not comparable directly (e.g. differences in network topology, structure of customers, climate conditions, etc.), see e.g. Weyman-Jones (1995). Furthermore, data availability and data consistency is supposed to be a problem in practise.

In recent years, different incentive regulation approaches in electricity grid regulation summarized above have been implemented in many countries worldwide. Comprehensive practical experience is available also in selected European countries, e.g. (i) revenue-cap regulation in Norway, (ii) price-cap regulation in UK, and (iii) yardstick-regulation in The Netherlands. For details on country-specific experience with incentive regulation it is referred to Auer (2008).

3.3 Cost Drivers due to Large-Scale DG/RES-E Grid Integration

The excursion on regulatory practise in electricity grid infrastructure planning and operation above clearly demonstrates that grid operators are forced to be "cost efficient". However, based on these regulatory circumstances grid operators are reluctant to invest in general, regardless whether or not any DG/RES-E integration activities discussed in this context. Moreover, in case of large-scale DG/RES-E integration plans the economic situation for electricity grid operators gets even worse since there are further cost drivers having to be born by electricity grid operators, especially on distribution grid level.

Selected examples of currently unconsidered extra cost drivers on distribution grid level caused by large-scale DG/RES-E integration are as follows (see e.g. Auer (2007d)):[19]

- Completely new design criteria and operational concepts are necessary due to bidirectional load flows in case of significant amounts of DG/RES-E generation.
- Significant reinforcements, upgrades and extensions of existing network infrastructure elements (overhead lines, cables, transformers, switching devices, etc.) are necessary.
- Higher technical standards and new concepts for ancillary service provision like voltage and frequency regulation, accounting and billing devices and procedures are necessary.
- The installation of new information and communication technologies (ICT) is necessary to be able to manage active and intelligent distribution grids.
- Higher transaction cost have to be taken into account to operate actively managed distribution grids due to the increasing number of market actors.

Due to the fact that above mentioned extra cost for distribution grid operators in case of DG/RES-E integration are not explicitly taken into consideration in the existing grid regulation models (see section 3.2; box 3) – but cost recovery is essential for capital intensive infrastructure investments being effectively sunk once the investment is made – the risk of asset stranding for distribution grid operators is too high. Therefore, based on the existing regulatory environment distribution grid operators might not be willing to integrate DG/RES-E projects on large-scale.

[19] Besides extra cost drivers caused by large-scale DG/RES-E integration there exist a variety of further inherent cost drivers for distribution grid operators. The main "traditional" cost drivers on distribution networks are the provision of overall capacity taking into consideration power flows, voltage level and fault level issues, and the time of use as this drives overall peak requirements. Absolute volume delivered on the distribution system usually is not to be a significant cost driver by distribution grid operators. Furthermore, regulatory incentives to maintain predefined levels of quality of service and to minimize losses also have significant influence on the cost basis of distribution grid operators (see e.g. DTI (2006)).

From the distribution grid operator's point-of-view, the disincentives for any kind of investment into the existing grid infrastructure can be immediately derived from the basic grid regulation formula shown in box3 of section 3.2. The basic "RPI-X" incentive regulation formula is as follows:

$$P_t = P_{t-1} * (1 + RPI - X)$$

where
P_t..........authorized price-cap in year t
P_{t-1}.......authorized price-cap in year (t-1)
RPI.......annual inflation index (Retail Price Index)
X...........productivity offset

This formula determines the authorized price (tariff) a grid operation can set within a regulatory period, incorporating also efficiency improvements (based on cost benchmarking; see section 3.2, box 2, in detail) over the years.

Regardless of specific investments into the distribution grid infrastructure in the context of DG/RES-E integration or investments in general, any investment decision of a grid operator is based on the basic economic criterion that maximises revenues minus cost over a predefined period.

In detail, the analytical framework describing an economic decision of a grid operator for the most common incentive regulation models (price-caps and revenue caps) looks as follows:[20]

<u>Price-Caps:</u> $\text{Profit}\ \pi = \max_{x,c}\ px - c \qquad \text{whereas} \qquad \text{p} = \text{fixed} \quad \text{x, c} = \text{variable}$

<u>Revenue-Caps:</u> $\text{Profit}\ \pi = \max_{p,x,c}\ px - c \qquad \text{whereas} \qquad \text{p, x, c} = \text{variable}$

With respect to any changes of the cost basis of grid operators (e.g. increase of capital cost in case of new investments) – ceteris paribus[21] – there is no difference for the two most prominent grid regulation models (price-caps and revenue caps) presented above concerning the disincentives to invest.

In the following, a thought experiment shall demonstrate the reluctance of distribution grid operators (being subject to "ex-post" oriented price-cap or revenue-cap regulation) to invest into the grid infrastructure, in general, and to accept extra cost

[20] The most obvious difference between the price-cap and revenue-cap regulation model shown above is the degree of freedom for setting several different parameters independently which determine revenues and cost. Whereas in case of revenue-caps several parameters (price, quantity, cost) are variable, this is the case only for quantity and cost for price-cap regulation models. One of the resulting effects of these differences is e.g. the problem to implement energy efficiency initiatives in case of price-cap regulation models as a result of strong incentive for grid operators to maximise quantity (i.e. electricity delivered) and, subsequently, profits rather than to decrease the amount of electricity delivered.

[21] This means, remaining parameters are assumed to be unchanged.

for the provision of technical infrastructure and equipment enabling large-scale DG/RES-E grid integration in particular:

- If $c_{DG/RES}$ ($c_{DG/RES}$ > 0) is assumed to be the extra cost for grid operators driven by the integration of large-scale DG/RES-E generation facilities, the initial cost basis c of a distribution grid operator is increased to $c_{new} = c + c_{DG/RES}$.

- If these extra cost are not eligible in the grid regulation model (i.e. the extra cost can't be socialised in the grid tariffs directly) there is no incentive for distribution grid operators to favour any DG/RES-E connection, simply because increasing DG/RES-E integration cost decrease profits (i.e. revenue minus cost):

$$\left.\frac{\partial \pi}{\partial c_{\mathrm{new}}}\right|_{c,x,p=cons\tan t} < 0$$

This analytical relationship impressively demonstrates why currently implemented grid regulation models result in reluctant investment behaviour of distribution grid operators in general and as far as DG/RES-E grid integration is addressed in particular.[22]

[22] Underinvestment into the electricity grid infrastructures is one of the most critical medium- to long-term problems of incentive regulation models. Moreover, the medium- to long-term result of underinvestment into electricity grid infrastructures is decreasing security of supply.

4. Forward-looking Regulatory Framework Supporting Large-Scale DG/RES-E Integration

Two exemplary implementations of forward-looking and RES-friendly legislative frameworks concerning electricity gird regulation shall be presented in subsequent sections. The selection of the UK and Germany is not intended to exclusively demand best practice regulation to be in place in those two countries only but shall introduce attempts to improve the framework conditions for developing RES by incentivising grid operators to bear specific additional investment costs or simply by implementing a well defined shallow grid integration approach.

4.1 Best Practise Case: Recent Innovations in the Electricity Grid Regulation Model in UK

The UK has long tradition in regulating its electricity distribution grids based on incentive regulation models. Already in 1995 the regulator has implemented price-cap regulation (see Auer (2008) in detail). Although the price-cap regulation model has fulfilled its purpose (i.e. improving cost efficiency) in the two regulatory periods from 1995-2000 and 2000-2005, in the course of time the disincentives for investments into the electricity distribution grid infrastructure have become increasingly obvious. Moreover, in the UK empirical evidence has become increasingly visible on the reluctance of investments into the electricity distribution grid infrastructure.

Therefore, in 2005 fundamental amendments of the distribution grid regulation model have been conducted, trying to trigger both: (i) traditional investments into the distribution grid for maintenance of the infrastructure assets and (ii) extra investments to provide a level playing field for accelerated grid integration of DG/RES-E generation technologies. More precisely, the two dimensions of changes of the incentive regulation model in UK are as follows:

- the philosophy of allocating DG/RES-E grid integration cost has been changed from “deep” towards “shallow” charging and

- the extension of the traditional price-cap regulation formula now explicitly considers an “ex-ante” element, enabling direct socialisation of extra grid-related cost for DG/RES-E integration in the grid tariffs.

In detail, the following amendments of UK's incentive regulation model have been conducted in April 2005 (see e.g. DTI (2006), Auer (2007d)):

- Same Boundaries on both Ends of the Grid: Prior to April 2005, demand and generation customers were charged differently on distribution grid level. DG/RES-E generators paid connection charges for all measures required to integrate them into the distribution grid (i.e. deep integration approach) whereas demand customers paid more limited connection charges (i.e. shallow integration approach).[23] In April 2005, a common connection boundary has been introduced across generation and demand, i.e. new DG/RES-E generators connecting to the distribution grid now also pay "shallower" connection charges.

- Socialisation of Integration Cost: Electricity distribution grid operators are allowed to recover their grid-related connection and integration cost of DG/RES-E generation facilities directly in the distribution grid tariffs by a combination of pass through (80% of connection cost) and an incentive per $kW_{DG/RES}$ connected (2.16 €/$kW_{DG/RES}$ (singular) and 1.44€/ $kW_{DG/RES}$/yr (annually)).

- Innovation Funding Incentive (IFI): The Innovation Funding Incentive (IFI) is intended to provide funding for particular DG/RES-E integration projects focused on the technical development of distribution networks to deliver extra value (i.e. financial, supply quality, environmental, safety) to end consumers. IFI projects can incorporate any aspect of distribution system asset management including connection of DG/RES-E generation facilities. A distribution grid operator is allowed to spend up to 0.5% of its annual revenue on eligible IFI projects and can socialise a significant amount of associated cost from its network users (e.g. 90% in 2005/2006).

- Registered Power Zones (RPZ): In contrast to the IFI, Registered Power Zones (RPZs) are focused specifically on the connection of DG/RES-E generation facilities to distribution grids. RPZs are intended to encourage electricity distribution grid operators to develop and demonstrate new, more cost effective ways of connecting and operating DG/RES-E generation facilities. For licenced RPZs, the incentive element per $kW_{DG/RES}$ of DG/RES-E generation facility connected is increased for the first five years of operation from 2.16 €/$kW_{DG/RES}$ to 4.3 €/$kW_{DG/RES}$.

[23] Electricity distribution grid operators are provided with a revenue stream from demand customers by so-called 'Distribution Use of System Charges (DUoS)' covering the ongoing provision of the distribution grid and spreading the cost of connection of demand customers over the long-term.

4.2 Best Practise Case: Recent Innovations in the Electricity Grid Regulation Model in Germany

Germany's track record in RES-E development is among the most impressive and successful in Europe. While historically this success is owed to a timely stable and economically favourable promotion mechanism, recent legislation strengthens transparency in the rules for RES-E grid access and tariffing of grid related services.
Legislation on the promotion of renewable energy sources in Germany dates to the year 1991. In 2000 the renewable energy act (EEG) was put in place and amended in 2004 as well as in 2009. This design of a national promotion schemes acted as a model, which was copied by many countries.
Regulations for access to the grid define a strictly shallow approach for connection cost allocation: Plant operators have to bear costs for the – immediate and priority - connection of the power plant to the nearest connection point providing sufficient voltage levels. In case of necessary reinforcements or extensions for using this connection point, grid operators have to bear corresponding costs or extra costs for the connection to a more distant location and are able to socialise these costs via grid tariffs.

Above this, special legislation for the connection of offshore wind farms has been put in place: In an enactment facilitating planning procedures for infrastructure projects (*Infrastrukturplanungsbeschleunigungsgesetz*) transmission system operators are committed to provide transmission lines linking substations of offshore wind platforms to technically and economically best suitable connection points of the existing electricity grid infrastructure. These transmission lines have to be put in place before the commissioning of offshore wind farms, construction of which started until end 2011. Corresponding costs on the side of grid operators are eligible costs to be socialised via grid tariffs. This regulation aims at streamlining planning procedures and facilitating financing of offshore wind projects (as financing of transmission lines has not to be borne by plant operators). At the same time, inefficient spending of electricity consumers' money for parallel submarine infrastructure shall be avoided.

German provisions do not provide extra incentives for the connection and integration of RES-E for grid operators (as is the case in the UK), but define clear responsibilities for cost allocation on the basis of a shallow approach of cost charging. In the case of offshore wind integration a – timely limited – super-shallow approach is applied.

4.3 Recommendations for Amendments of the Incentive Regulation Models

Recent innovations of the electricity grid regulation model in UK demonstrate the way forward for amending the traditional incentive regulation approaches enabling large-scale DG/RES-E grid integration. A precondition for DG/RES-E grid integration – as well as the implementation of smart grid concepts in the long-term (see outlook in section 5) – is the establishment of common connection boundaries both on the generation and demand side. Compared to the status quo, this implies shallower DG/RES-E connection charging policies in almost all EU Member States (see Table 1). Moreover, integration policies like that would go even more in line with the basic unbundling principles of the EC-Directives (see section 2 in detail).

German grid regulation does not provide comparable incentives for the integration of RES-E generators but defines clear boundaries for responsibilities (concerning costs) between plant operators and grid operators. The German incentive regulation model for grid operators does account for investment costs due to RES-E integration and therefore these costs on the side of grid operators for extension and reinforcement can be handed through into system charges in principle. These charges have to be approved by the regulatory authority.

The overarching amendment of the traditional incentive regulation model, however, has to be an extension of the traditional grid regulation formula towards forward-looking elements for remuneration and/or socialisation of DG/RES-E grid integration cost. Therefore, besides the well-known (1+RPI-X) factor an additional term has to be implemented into the existing incentive regulation model fulfilling at least the following features:

- Consideration of a mechanism to directly socialise – at least parts of – grid connection, grid reinforcement and grid extension cost in the distribution grid tariffs (e.g. direct cost pass through as well as other fixed connection (e.g. €/kW$_{DG/RES}$, €/kW$_{DG/RES}$/yr) and volume based (€/kWh) use of system charges having to be paid by DG/RES-E generators directly to distribution grid operators)[24] similar to UK's recently modified incentive regulation model.

[24] The volume based part of the use of system charge allocated to generators usually is called 'Generation Use of System Charges (GUoS)'.

- Provision of some kind of cost-reflective locational signals for DG/RES-E generators, e.g. on the basis of forward-looking long run incremental cost (LRIC) rather than solely in relation to the direct cost incurred of a specific connection of a single DG/RES-E generation facility.[25] This approach is supposed to minimise the problems associated with first movers and free-riding in case of more than one DG/RES-E generator on the same connection point on distribution grid level.

- Consideration of a mechanism to directly cover and/or remuneration operational cost allocated to innovative DG/RES-E grid integration projects (i.e. personnel cost for research, feasibility studies and preparatory operations of DG/RES-E grid integration projects) in the incentive regulation model.

- Avoidance of unmanageable complexity of additional terms in an extended incentive regulation formula.

Exemplarily, an extension of the traditional incentive regulation formula (e.g. price-cap and/or revenue-cap regulation model) can be indicated as follows (see e.g. Auer (2007d)):

$$P_t = P_{t-1} * (1 + RPI - X) + \Delta \mathrm{C}_{\mathrm{DG/RES}\,\mathrm{i,\,j}} * \Delta \mathrm{kW}_{\mathrm{DG/RES}\,\mathrm{i,\,j}} * (1 + RPI - LR_{\Delta C_{DG\,/\,RES\,i,\,j}})$$

whereas

$\Delta \mathrm{C}_{\mathrm{DG/RES}\,\mathrm{i,\,j}}$ ....specific cost for a distribution grid operator caused by the integration of a DG/RES-E generation technology i into an existing grid topology and/or smart grid concept j

$\Delta \mathrm{kW}_{\mathrm{DG/RES}\,\mathrm{i,\,j}}$ ......installed capacity of DG/RES-E generation technology i integrated into an existing grid topology and/or smart grid concept j

$LR_{\Delta C_{DG\,/\,RES\,i,\,j}}$ ......expected dynamic learning rate and/or economies of scale of specific grid integration cost caused by the integration of a DG/RES-E generation technology i into an existing grid topology and/or smart grid concept j

It is important to note, that the analytical approach presented above only suggests the cornerstones of a possible way forward to extend the traditional incentive regulation model. Although it is still incomplete and subject to further disaggregation and empirical scaling, innovations in electricity grid regulation are obvious at least in two dimensions:

[25] In general, the decision on the boundary between fixed connection charges and volume based 'Generation Use of System Charges (GUoS)' – both having to be paid by DG/RES-E generators to distribution grid operators – needs to take account of the desirability of reflecting cost to DG/RES-E generators on a forward-looking long-run incremental cost (LRIC) basis. These charges, furthermore, should be cost reflective and also incorporate a sensible apportionment of forward-looking LRIC providing both correct signals and cost-recovering mark-ups. However, according to the Ramsey-Boiteux rule (see e.g. Ramsey (1927) and Boiteux (1971)) the mark-up should minimise distortions. This also implies that usually 'Generation Use of System Charges (GUoS)' and 'Distribution Use of System Charges (GUoS)' are set differently, due to the differences in price elasticities of generation and demand customers.

- implementation of a forward-looking element enabling ex-ante socialisation of grid related cost caused by the integration of DG/RES-E generation,

- consideration of a dynamic element putting downward pressure on specific grid integration cost (e.g. due to technological learning and economies of scale on distribution grid level) with increasing shares of DG/RES-E generation.

An amendment of the traditional incentive regulation model according to the basic principles shown above finally shifts the connection boundary between the DG/RES-E generation facilities and the distribution grid infrastructure increasingly towards the DG/RES-E generators. Moreover, if grid infrastructure related cost of RES-E integration are allocation to distribution grid operators rather than to RES-E generators, there also exist direct interdependences with the design of RES-E promotion instruments (e.g. like feed-in tariffs).[26]

More precisely, a re-design of RES-E promotion instruments is necessary, if parts of the initial cost (previously allocated to the RES-E power plant) are assigned to the distribution grid infrastructure (e.g. grid connection cost) and socialised in the distribution grid tariffs. For a comprehensive consideration of these interdependences including empirical modelling of RES-E deployment for different cost allocation policies of RES-E grid integration cost it is referred to e.g. Auer at al (2007a, 2007b).

[26] In case of tradable green certificate (TGC) support schemes of RES-E generation technologies an allocation and socialisation of several grid related integration cost (i.e. grid connection, grid reinforcement/upgrading) to the grid tariffs finally shall also result in lower certificate prices indicated on the TGC market (due to lower long-run marginal RES-E generation cost).

5. Outlook: The Future Vision of Smart Grids

Previous sections have shown that the existing electricity distribution grids – being the result of technological and institutional development over many decades of the 20th century – are increasingly changing its architecture to enable the injection of dispersed and large-scale DG/RES-E generation on distribution grid level. Moreover, active distribution networks are characterised by novel concepts and interactions of several network users involved (e.g. generators, grid operators, consumers, etc.) on different scales and based on different conceptual models, e.g.

- intelligent local micro-grids,
- active regional networks supported by new information and communication technologies enabling virtual power plant solutions, and finally
- internet-compatible smart grid solutions taking intelligent, active electricity network concepts to the global scale.[27]

However, at present there doesn't exist a clear picture about the most promising smart grid concepts to be implemented in the future. Scientific research and technological development in this context are still in a premature phase, e.g. recently a so-called "Technology Platform on Smart Grids" has been implemented within the 7th Framework Programme of the European Commission trying to bundle several activities, industries and stakeholders in this field (see e.g. Figure 10 as well as www.smartgrids.eu).

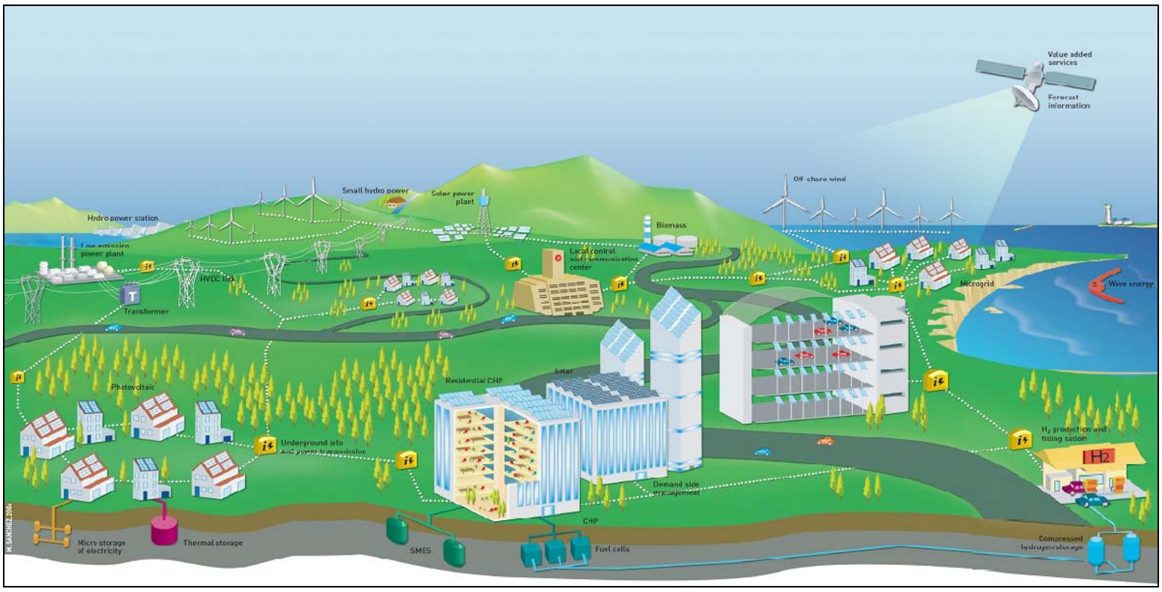


Figure 10. The future vision of a smart grid. Source: TP Smart Grids (www.smartgrids.eu)

What's to be even more tangible, is, that technological innovation and development of new and sophisticated smart grid solutions will not be for free. Moreover,

[27] According to EC (2003), the ultimate vision of internet-compatible smart electricity networks in the long-term is that *"every node in the electricity networks of the future will be awake, responsive, adaptive, price-smart, eco-sensitive real-time, flexible, humming…"*. For this vision, the World Wide Web itself serves as a model where the flow of information on global scale already uses the concept of distributed control where each node, web host computer, email server or router acts autonomously under a global protocol.

investment needs in case of a transformation of currently existing passive electricity distribution grids towards actively managed intelligent smart grid solutions are enormous. Besides the extra cost drivers caused by large-scale DG/RES grid integration already listed in section 3.3, a variety of further investments are supposed to be necessary for the realisation of sophisticated smart electricity networks in the long-run.

Figure 11 presents a rough qualitative indication of the extra investment needs into the existing, passive distribution grids for increasing shares of dispersed DG/RES-E generation based on smart grid solutions. Furthermore, also necessary re-investments into the traditional distribution grid infrastructure are indicated for increasing shares of dispersed DG/RES-E generation. The starting point of traditional re-investments depends on the point in time in the investment cycle of the existing passive distribution grid infrastructure. The total investment needs are finally the aggregate of both traditional re-investments and investments into new and smart solutions. The individual amount of each of these two investment categories depends on the future degree of decentralisation and innovation to be implemented into an electricity system.

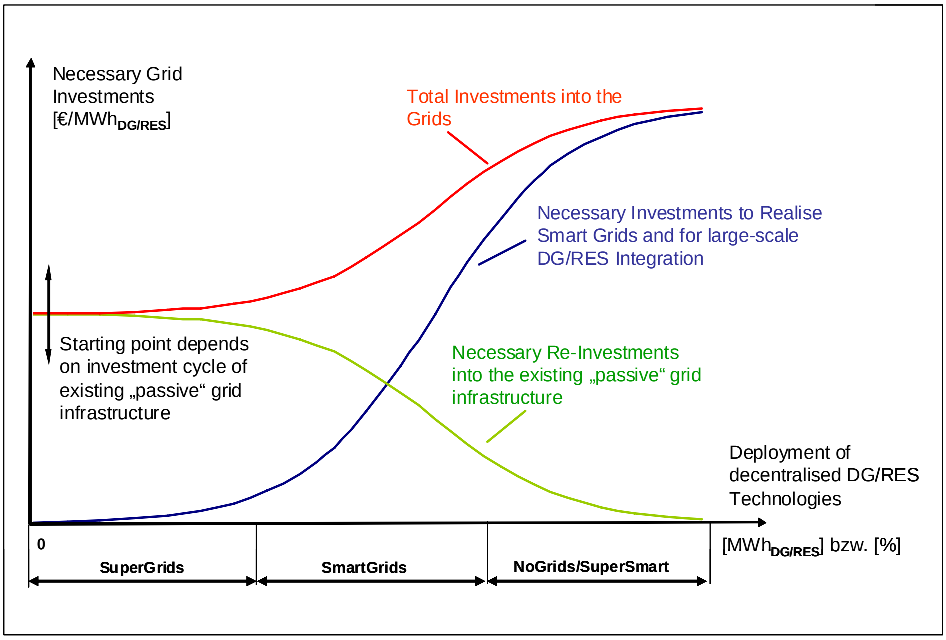


Figure 11. Investments needs into the existing distribution grids for the realisation of smart grid concepts with high penetration of DG/RES-E generation. Source: Auer (2008).

The basic economic principles shown in Figure 11 are subject to further research and development in order to get a better insight and understanding about the investment needs of smart grid solutions in the future.

References

Armstrong M., S. Cowan, J. Vickers: “Regulatory Reform: Economic Analysis and British Experience”, *MIT Press*, Cambridge, Massachussetts, U.S., 1994.

Auer H.: “Grid Regulation in Competitive Electricity Markets”, Habilitation Thesis, Vienna University of Technology, (forthcoming) 2008.

Auer H., C. Obersteiner, W. Prüggler: “Comparing different cost allocation policies for large-scale RES-E grid integration in Europe”, *International Journal of Distributed Energy Resources*, Vol. 3, No.1, p. 9-30, ISSN 1614-7138, 2007a.

Auer H., C. Obersteiner, W. Prüggler, L. Weissensteiner, T. Faber, G. Resch: „Guiding a Least Cost Grid Integration of RES-Electricity in an extended Europe“, Action Plan, Project GreenNet-Europe, 2007b.

Auer H., R. Haas: „Triggering Investments into Cross-Border Transmission Capacities in the European Electricity Market“, *in Proceedings, 9th IAEE European Energy Conference ´Energy Markets and Sustainability in a Larger Europe´,* 10-13 June, Florence, Italy, 2007c.

Auer H.: “Grid Integration of Distributed Generation”, *Script: MSc Programme ´Renewable Energy in Central and Eastern Europe´*, Vienna University of Technology, 2007d.

Auer H.: “The Relevance of Unbundling for Large-Scale RES-E Grid Integration in Europe”, *Energy & Environment*, Vol. 17, No. 6, p. 907-928, ISSN 0958-305X, 2006.

Auer H., C. Huber, M. Stadler, C. Obersteiner: “Large-scale RES-E Grid Integration: Strategies, Requirements and Cost”, Re-xpansion Project Report, 2005.

Averch H., L. Johnson: “The Behavior of the Firm Under Regulatory Constraint”, *American Economic Review*, Vol. 52, p. 1053-1069, 1962.

Barth R., C. Weber, D.J. Swider: ”Distribution of costs induced by the integration of RES-E power”, submitted to *Energy Policy*, Manuscript No. JEPO-D-07-00521, 2008.

Baumol W. J., J.C. Panzar, R. D. Willig: “Contestable Markets And The Theory of Industry Structures”, Academic Press Ltd., Revised Edition, ISBN 0-15-513911-8, 1983.

Baumol W.J., D.F. Bradford: “Optimal Departure from Marginal Cost Pricing”, American Economic Review, Vol. 60, p. 265-283, 1970.

Boiteux M.: “On the management of Public Monopolies Subject to Budget Constraints””, *Journal of Economic Theory*, Vol. 3, p. 219-240, [translated from the original in French: “Sur la gestion des monopoles publics astrients a l’équilibre budgetaire”, *Econometrica*, Vol. 24, p. 22-40, 1956], 1971.

Comnes G.A., S. Stoft, N. Greene, L. J. Hill: “Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning Issues”, Volume I, Report LBNL-37577, UC-1320, Lawrence Berkeley Laboratory, U.S., 1995.

DTI (Department of Trade and Industry): „A Guide to Distribution Network Operation Charging – Connection and Use of System Methodologies“, URN Number: 06/653, available on www.distributed-generation.gov.uk, 2006.

ETSO (European Transmission System Operators Association): www.etso-net.org

Fillipini M., J. Wild: “Regional differences in electricity distribution costs and their consequences for yardstick regulation and access prices“, *Energy Economics*, 23, pp 477-488, 2001.

Jamasb T., K. Neuhoff, D. Newbery, M. Pollitt: “Long-Term Framework for Electricity Distribution Access Charges”, Project Report for OFGEM, University of Cambridge, 2005.

Nera: “A Review of DEA Benchmarking of the NSW Distribution Business”, *Report for Energy Australia*, NERA, London, 1999.

Ramsey F.: „A Contribution to the Theory of Taxation“, Economic Journal, Vol. 37, p. 47-61, 1927.

Shleifer A.: “A theory of yardstick competition”, Rand Journal of Economics, Vol. 16, p. 319-327, 1985.

Technology Platform “SmartGrids”: www.smartgrids.eu

Van Werven M.J.N., M.J.J. Scheepers: “The Changing Role of Energy Suppliers and Distribution System Operators in the Deployment of Distributed Generation in Liberalised Electricity Markets”, Project Report DISPOWER, Report No. ECN-C-05-048, 2005.

Vogel P.: “Efficient Investment Signals for Distributed Generation”, Institute for Energy Economics, University of Duisburg-Essen, 2008.

Weyman-Jones, T.: “Problems of Yardstick Regulation in Electricity Distribution”, in: *The Regulatory Challenge*, edited by M. Bishop, J. Kay and C. Mayer, Oxford-New York, Oxford University Press, 1995.