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Regulatory Practices Supporting Deployment of Renewable Generators through Enhanced Network Connection

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ERRA-NARUC Joint Issue Paper:

Regulatory Practices Supporting Deployment of Renewable Generators through Enhanced Network Connection

The present report of the Issue Paper includes the draft version of the theoretic discussion part of the four key issues raised by the call: Determination of the maximum connectable intermittent capacity to the system; Queue management; Connection tariff methodology for RES-E generators and the Regulatory incentives to connect RES-E. With the structure of the report we follow the same order as we start from the TSO focused areas and finish with the more DSO related topic.

It contains four case studies on the present practices of the selected four countries - Bosnia and Herzegovina, Italy, Hungary and Turkey.

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EXECUTIVE SUMMARY

The objective of the issue paper is to assess the role of four non-tariff regulatory issues in RES-E deployment: methods applied to determine the volume of intermittent RES-E capacity that can be connected to the public grid, queue management, connection charging and the incentive system for DSOs to integrate more RES-E to the electricity system. Present good practices are assessed on the basis of the EU and CEE regional experience, supplemented by four country case-studies (Bosnia and Herzegovina, Hungary, Italy and Turkey) in order to evaluate their practices with respect to the four general regulatory issues analysed in the first chapters of this paper.

Although tariff elements are deterministic in driving RES-E investments, even when effective incentives are in place (e.g. in the form of feed in tariffs or premiums) the penetration of RES-E capacities is often constrained by network connection capacities. These barriers to further RES-E deployment and alternative solutions to the problems need to be identified. This is why the assessed four non-tariff areas are important for the ERRA member countries as well.

TSO's role in determining the connectable RES-E capacity to the grid

Concerning the TSO's role in determining the connectable RES-E capacity to the grid, there is a tendency to start with a conservative estimation which is a sensible approach when TSOs and regulators have no experience with large scale penetration of RES-E. With more experience this 'initial' estimate can be increased by 'soft' measures such as improved grid and market regulation (better forecasting, gate closure), procurement of more reserve capacities in case reserve capacity availability constrains RES-E or integrating intermittent capacities into the ancillary service market. As the application of 'soft' measures is generally cheaper than network expansion and upgrade, they should receive priority.

A preliminary step for TSOs in this process is the collection of information on the actual available grid capacity, which generally requires the application of physical network models. A second task is data collection on the RES-E resource potential and production level. This is an important aspect from the point of view of capacity planning as e.g. more evenly distributed wind generation across a country would result in less volatile electricity generation.

When it is not the grid that limits RES-E penetration but the available reserve capacity (e.g. in the case of Hungary), than regulatory efforts should concentrate on this market segment. An obvious first solution is to prescribe the participation of intermittent producers in the reserve market and locational diversification of wind generation in order to reduce their overall volatility. Cooperation with the neighbouring countries in the reserve markets could also help to increase the amount of connectable RES-E in these situations.

Recommendation: A staged approach of TSOs is a prudent solution when there is limited knowledge about the impacts of sizeable RES-E penetration. The first steps should include the collection of information on network capabilities, the RES-E production potential and network development costs. As a next step 'soft' measures, such as improved regulation on scheduling RES-E should be used before the more expensive network upgrade is undertaken. The upgrade due to RES-E developments should be synchronized with the long term network development plans.

Queue management

When an effective tariff system is in place to support RES-E, regulators often receive a large number of grid connection applications within a limited time frame (such as the case of the first Turkish wind tender) that needs to be managed often in the context of limited grid access capacity (queue management). This poses a highly demanding administrative burden on regulators/governments while also presenting the additional problem of finding ways to allocate limited grid access capacity among applicants. As a first solution, regulators usually apply the 'first come first serve' or the 'pro rata' (all applicants receive a reduced share of their original bid) allocation methods which result in an economically inefficient outcome. In this case those applicants that would be willing to pay more for the scarce resource will not receive a higher portion of the available capacity. Moreover, the scarcity of the resource does not translate into additional income for the regulator and potentially lower prices for the final consumers. In addition, this type of allocation is not able to filter out 'junk' applications, the main purpose of which is to collect rents from other investors while effectively blocking the connection of future entrants.

The ultimate and most efficient solution to this problem is to allocate the limited connection capacity in a competitive tendering process where applicants receive connection capacities according to their willingness to pay for the connection right. The main advantage of this selection method is that the resulting prices will reflect the economic value of the connection right and the resulting income could be used to either reduce consumer prices or increase the network capacity at the critical points.

In addition to the allocation methods further instruments are also available for regulators to improve their queue management processes. Deposit requirements for connection rights could filter out 'junk' applications, while inserting milestones into the application-realisation cycle could help to keep the original timeframe of the connection schedule and prevent blocking the connection point by stalling projects.

Recommendation: Tendering is the most efficient way to allocate available connection capacities among a large number of applications. Although it requires more preparation from the TSO/regulator side than the 'first come first served' or 'pro rata' allocation methods, tendering is a feasible solution in ERRA member states as well (see the example of Turkey).

Connection charging

Many European countries apply reduced connection charges for renewable generators to promote them in order to fulfil national renewable targets. This so called shallow cost approach – when project promoters only pay the cost of network connection up to the connection point – could help the uptake of certain RES-E technologies as connection costs often amount to 5-15% of the total project cost due to the spatial distribution characteristics and smaller unit size of RES-E technologies.

In deep connection charge regimes project developers have to cover not only the cost until the connection point but also the necessary network upgrade beyond that point. As an advantage, this gives a strong locational signal to project developers to find the most economical entry points to connect to the grid. In this case investors face the true cost of their development and can make their decision on the basis of the full impact on the network. The main disadvantage of this approach is that the reinforcement of the existing network generally creates positive 'externalities' to other users, e.g. consumers in the given area or consequent RES-E developers who do not have to pay for this reinforcement ('first mover disadvantage' problem). This could prompt developers to wait until the network is able to integrate them without much upgrade, but this could jeopardise compliance with RES-E targets. A third option is the hybrid cost charging approach when the RES-E developer pays for the direct connection part of the new line but only a fraction of the further development of the existing grid infrastructure behind the connection point. When hybrid and shallow cost approaches are used, regulators must carefully design the cost allocation to the end user, a process called 'cost socialisation'. Strict cost control from the regulatory side is needed in order to avoid an unnecessary cost increase for the consumers.

Recommendation: it is advisable to follow a stepwise approach related to the connection charging regime in the ERRA countries. The shallow cost approach should be used only for a limited period in the beginning of RES-E deployment and then substituted with the deep cost charging approach before more sizeable RES-E developments take place. This choice is supported by the lower purchasing power in the ERRA countries, as this places the cost burden on the producer, thus limiting the price impact on the final consumers. In addition, if DSOs have a discretionary role in this process (e.g. due to the lack of detailed regulation of certain elements) the shallow cost approach might deteriorate their incentives to actively participate in this process.

DSOs role in distributed generation

Large scale distributed generation (DG) deployment impacts the financial status of DSOs. In a revenue or price cap regulation this impact is negative, which explains why DSOs have no incentives to take an active role. The underlying rationale is that the cost of DSOs are driven by power demand, as they have to secure the operation of the network for peak demand hours, but their revenue is based on the total energy demand. In addition, there is a time lag between the network investment and its inclusion in the revenue cap (CAPEX time shift problem) and its recognition is often uncertain during the cost review. From an economic point of view the main problem is that network tariffs are not paid by the actors that generate these costs: producers in general and prosumers (entities producing and consuming electricity at the same time) in particular, and that flat rate volumetric tariffs do not reflect the marginal cost of network use (peak versus off-peak). Under rate of return network regulatory regimes DSOs have higher incentives to participate in DG developments, but the regulator must safeguard that no overinvestment takes place.

Various tools are available to provide stronger financial incentives for DSOs to more actively participate in the DG deployment process. On the one hand, network tariff schemes can be redesigned in a way that network costs and the derived benefits are better matched within the consumer base either by moving towards deep connection charges or by expanding the network tariffs to generation as well. In addition, time-of-use (ToU) network tariffs paid by both consumers and producers would provide signals for all network users towards minimizing the overall cost of maintaining an adequate electricity grid. However, the introduction of ToU tariffs might be difficult in countries with simple measuring and billing schemes. On the other hand, revenue adequacy can be met even in case of volumetric tariffs as well, if the incentive regulation is not practised in its classical form but includes mechanisms that reduce the CAPEX time lag. DSOs are more willing to engage in DG developments if the time lag to recognise their cost is shorter and more certain, e.g. through the application of 'enlargement factors' for cases of network restructuring. DSOs can also be motivated to take on the risk of investing in innovative technological solutions through co-financing such projects from public funds. However, these latter solutions are more adequate for higher income ERRA countries, where more public funding is available and metering, billing systems are more sophisticated. For lower income countries simpler schemes, such as radio controlled or twin meters (e.g. Serbia) are essential to keep in order to maintain the already achieved consumption shift to hours of low load.

DSOs can follow basically three different approaches in the process of planning/connecting/operating RES-E plants in their control area. It includes the most conventional '*Fit and Forget Approach'*, the *Reactive network integration* (sometimes called '*only operation*' approach) and the *Active distribution system management*. Most ERRA member states are in an initiating phase of their RES-E development, and DSOs are characterised presently by the Fit and Forget approach in their network management. The Active system management option is too advanced and costly for most member states, so they should focus their effort first on the more economical options, e.g. the coordinated network development or group processing methods.

Recommendation: To achieve active participation of DSOs in the DG deployment process, the most adequate tool for the ERRA countries is the reduction of the time lag for DSOs in receiving the reimbursement for their grid infrastructure developments that are aimed at the improved deployment of DG solutions. Presently applied solutions, such as radio controlled meters should be kept, as these are economic options to reach a shift in consumption.

Case studies

The case studies assess countries on different levels of their RES-E developments with various non-tariff policies. The countries are not only characterised by the diverse advancement of their electricity market regulation, but also by the different drivers of RES-E deployment.

Bosnia and Herzegovina is in an early phase of RES-E development. As the country has excess electricity production and a high share of hydro in its generation portfolio, presently there is little demand for further RES-E developments. The country has an ambitious plan to expand its RES-E base in the near future, but due to the previously mentioned factors the country currently only explores the option of higher RES-E deployment, without actual investments. Lack of information and the complex regulatory environment characterised by a double administrative burden due to the separate structures on the state and entity level also contribute to the higher level of investment uncertainty.

In contrast, Italy is one of the leading countries in promoting RES-E generation. Its extraordinary growth in RES-E based electricity generation (PV and wind) is not only fuelled by high production subsidies, but network connection is also regulated in a very progressive way. Grid operators play a very active role in the connection process: they have to expand the network beyond the connection point if RES-E development requires it. The connection process is regulated in detail, leaving minimal discretionary role for grid operators.

Italy applies auctions to allocate connection capacities to new entrants. This process selects the highest bidder, and at the same time simplifies the connection process and queue management as well. Auctioning requires detailed knowledge on the part of the regulator on the connectable capacity of each specific connection point. The regulator and the TSO have to possess all necessary information on grid status (grid modelling) and on the local RES-E potential (electricity system modelling) in order to carry out the process effectively. Active participation is demanded from RES-E developers as well: they have to participate in the connection process in a timely manner and - with the exception of micro-generators - RES-E plants have to participate in the reserve market as well (regulability).

Although Hungary has a slow uptake of RES-E technologies, it presents an interesting case from many aspects. The first is the determination of the connectable wind capacity by the TSO. As the network is quite strong and stable, the TSO determined wind capacity limits based on the reserve power capacity need, as if wind capacity was one large intermittent power plant. This assumption is supported by the fact that wind plants are concentrated in the Northwest of the country. Although a similar methodology was applied, the targeted wind capacity level was increased from 330 MW by an additional 410 MW during a tendering process of 2009. According to the TSO, this increase was allowed by the mandatory locational diversification and the required regulability of the wind plants. A second aspect is that pro-rata allocation - applied in the first wind tender - is inefficient, resulting in the rent-seeking behaviour of RES-E developers to reach an economically efficient size. Additional requirements (location, regulability and size) were added to the selection procedure in order to solve this problem. The tender was cancelled in its final stage by a political decision with a long lasting negative impact on the wind capacity deployment in the country. Reopening of a new tender is still awaited by investors but the governmental decision is kept postponed.

Regulation sets only higher level guidelines for connection rules, which increases the discretionary role of the DSOs. This led to a practice where RES-E developers engaged in a strained cooperation with DSOs in order to optimise location and cost sharing, and sometimes they cover extra costs in order to ensure timely connection. In many cases developers had not used the connection charge reduction options offered to RES-E units by the regulation in order to maintain the cooperative attitude of the grid operators.

Turkey has shown a very dynamic RES-E development for the last years, fuelled by its proactive renewable policy aiming to reduce import dependency and to meet the strong growth in electricity demand. With its increasing electricity demand and rather underdeveloped electricity grid, Turkey needs substantial grid developments and better forecasting and monitoring tools to support further RES-E connections to its system. Turkey applies a unique queue management system for wind installations, where project promoters participate in an auctioning process in case of multiple applications for a given connection point. This is an effective and transparent auctioning method to handle the queues of applicants. At the same time by applying this tool, the TSO receives information on the promoters' willingness to pay, and also on the locations where the grid needs to be reinforced in order to accommodate more RES-E capacities. A further regulatory tool to promote RES-E development is the significant reduction (up to 85 %) of the connection and grid usage fees paid by RES-E projects for a period of up to 5 years.

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INTRODUCTION

While the main tools to promote higher RES-E penetration in the electricity system are the financial support schemes, either in the form of operating assistance (Feed-in tariffs, green certificates) or investment support, network related elements also play a crucial role in RES-E development.

This paper focuses on four themes related to network integration:

1. Determination of the maximum connectable intermittent capacity to the system;
2. Queue management;
3. Connection tariff methodology for RES-E generators;
4. Regulatory incentives to connect RES-E.

These four areas cover the most important aspects of RES-E network integration with important tasks for regulators and network operators. The aim of the present paper is to highlight the most important issues arising in the regulation of these areas, to introduce those regulatory aspects to ERRA regulators and policy makers where they have to make key decisions in designing their regulations and also to present the practices of selected European countries on the functioning of these regulatory areas.

I. DETERMINATION OF MAXIMUM CONNECTABLE INTERMITTENT CAPACITY TO THE SYSTEM

Why do TSOs usually determine capacity limits on the amount of intermittent electricity production that can be connected to their grid? These generation units have an important characteristic that differentiates them from some of the traditional electricity producers: the electricity production of intermittent capacities is very volatile and cannot be forecasted precisely. Moreover, the best places for operating these units are frequently far away from the main consumer areas.

In some European countries it is problematic that areas with high quality RES potential (e.g. with high wind speed, or the sunniest part of the country) are far away from the main consumption areas. In Portugal, for instance, the best places for wind turbines are in the Northern, mountainous part of the country, where electricity consumption is low. As a result, the electricity network is not very strong in the North, therefore, if a new power plant is to be installed in this region, the network should be reinforced or new lines need to be built. Similar problems can be seen in Spain, Germany, or Italy.

The other reason why TSOs usually determine capacity limits for intermittent producers is the variability (weather dependency) of their electricity production, generating two main problems:

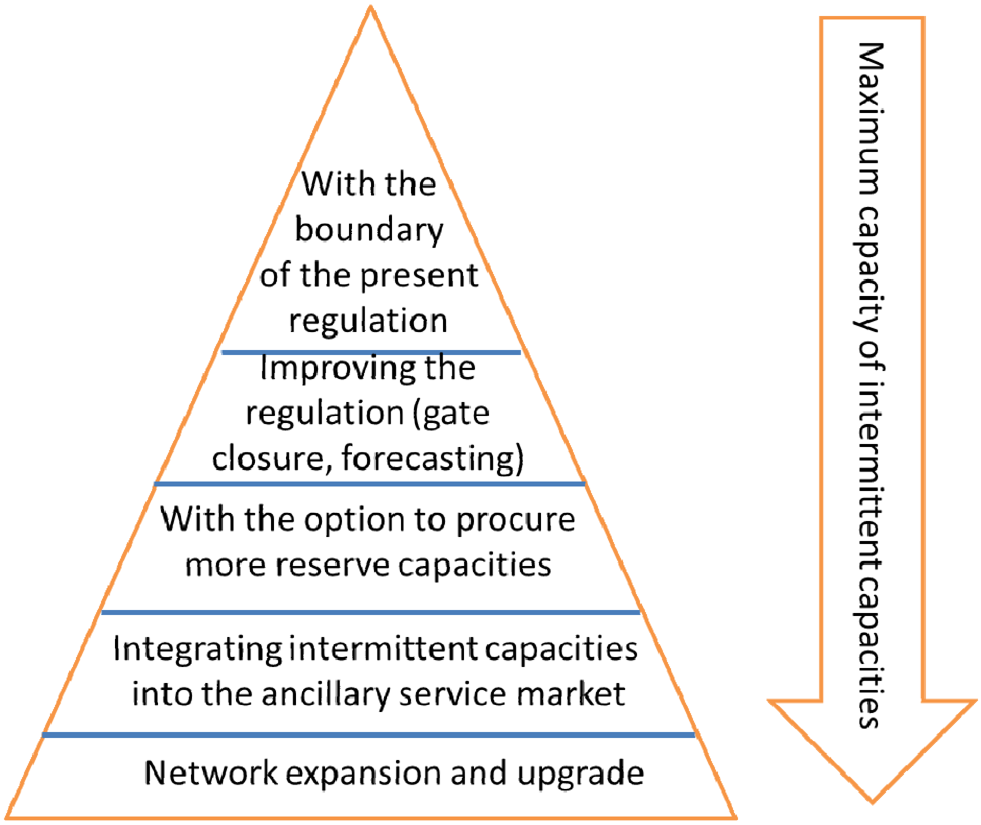
- Because of their weather dependency, wind and solar electricity generators are not always available, as a result these units cannot fully substitute traditional power plant capacities, e.g. in the reserve margin[1] calculations only a very low accountable capacity value can be assigned to intermittent producers.
- The accuracy of production forecasts for intermittent generators decreases very fast as we move away from real time. This accuracy depends on many factors, e.g. the gate closure time; the flexibility available to modify scheduled production; the incentives to meet scheduled production (e.g. the existence of penalties or an obligation to balance the deviation from scheduled production); or the type of model that wind or solar operators use for their forecasts. Because of the uncertainty of electricity production, more secondary and tertiary capacity reserves have to be procured by the TSOs.

TSOs set capacity limits on these producers due to the above mentioned special characteristics of the intermittent producers[2]. If TSOs would like to determine the maximum allowable wind and/or solar generating capacities, they also have to establish the conditions based on which the cap is set. This limit does not only depend on the technical characteristics of the

[1] The difference between the total available capacities in a country during peak hours and the peak load.
[2] Sometimes it is the Government and/or other regulator that sets these limits based on the calculation of the TSO.

network/system, but also on the regulatory environment. The following figure demonstrates how a higher cap for these producers can be set.

Figure 1: Determining the maximum connectable intermittent capacity



In most of those countries where the TSO faces this problem for the first time, it usually determines the maximum intermittent connectable capacity to the system in a very conservative way: in accord with the maximum limit of this capacity under the current regulatory framework (e.g. if gate closure time is not changed; intermittent producers are not motivated to meet their scheduled electricity generation, etc.). This was the case for the first wind tender in Hungary. The Hungarian Energy Office, as the Regulator calculated the maximum allocated wind capacity rights in such a way that it did not assume any change in the relevant regulation, including the very serious assumption that the TSO would procure the same amount of reserve capacities. This is the main reason why in most of those countries where capacity limits are determined for the first time, these limits are usually set at a low level.

Another renewable capacity limit can be set if the support value is relatively high and could significantly increase the end-user electricity price. The *government and the regulator sometimes set limits for renewable generators (not only for intermittent producers) taking into account the affordability of households and the competitiveness of industrial customers. Capacity limits could be a more frequent rationale than system or network reasons, but this is out of the scope of the present study.* The major barrier to integrating a higher number of intermittent producers to the system is that TSOs have an incentive to procure the minimum necessary secondary and tertiary capacity reserve. If TSOs procure more reserve capacities (that could also be provided by consumers as well), the penetration of intermittent producers could be higher. The integration of RES-E is also easier when intermittent capacities are not concentrated in a small area, because spreading the capacities to a larger area lowers the need for reserve capacities.[3]

It has to be noted that in general TSOs have not been motivated to allow more and more intermittent producers. There are multiple reasons for this. First of all, the TSO has to design the grid in order to operate it safely both with and without intermittent producers. The integration of RES-E requires increased network investments, and the energy regulator may not always approve these extra costs for the calculation of the system tariff. Second, a similar issue appears for the secondary and tertiary reserve market: the TSO can procure more capacities, but it is a question if the energy regulator accepts the procurement costs. Finally, grid stability and the security of supply are the TSO's main responsibilities, while many elements of RES-E integration (such as intermittent producers) erode exactly these goals. Consequently, the typical first reaction of TSOs is to prevent these situations and minimize their impact.

The capacity limits for intermittent producers can increase if wind and solar capacities are integrated to the reserve capacity markets. In the time slots when these capacities produce electricity, they can provide downward reserve capacity; if not then the need for reserve capacities is also smaller. In most Western-European countries the effective barrier to the connection of intermittent producers is the strength of the network. Besides the constraints on end user prices, reserve capacity needs could be another reason to set limits on intermittent power plants. In order to determine the maximum intermittent capacity, TSOs use grid models. These models represent the national transmission grids (sometimes the higher voltage level of the distribution system as well) including the main consumption areas, power plants and also the main network characteristics. Various scenarios (e.g. load patterns, power production mix, import/export position, etc.) are simulated in order to check network reliability using also the n-1 criteria: can the network still operate in a secure way if any of the network/system elements, including consumers, power generators and transmission lines, is suddenly dropped. With this kind of models TSOs can simulate the effects of connecting a new intermittent producer to the system, and estimate the probability of different power outages. Using network models helps the TSO to identify the weakest points of the network/system.

As the experience of the European countries with the highest RES-E penetration, such as Denmark, Germany and Italy shows, if the network (not only within the country itself, but in

[3] Spreading intermittent RES-E geographically to a larger area implies less volatile electricity generation, as the variability of various sites may offset each other (e.g. in case of wind).

the whole region) is strong enough and sufficient reserve capacity can be procured by the TSOs at a reasonable price, then the effective limits could be set at a very high level for the intermittent producers. An additional reason to apply some limit is the existence of loop-flows between European countries, where a larger country with lots of RES-E could 'export' its volatile intermittent RES-E production and its consequent problems to neighbouring countries.

How the TSOs determine the maximum connectable intermittent capacities – selected country examples

There are several studies assessing British wind power generation. They analyse the link between the potential of power generated by wind farms under various weather conditions and the amount of reserves needed to keep the required level of security of supply. The British TSO National Grid (2012)[4] assesses three possible scenarios to reach the minimum share of renewable targets. One of the possible scenarios is "The Accelerated Growth scenario", where offshore and onshore wind capacity grows to 49.1 GW and 23.5 GW, while predicted peak demand is 79.2 GW for 2030. These numbers show that there is no exact quantitative limit for wind capacity integration to the grid. If the Regulator allows the TSO to procure sufficient reserves and the required flexible capacities are available, it is possible to maintain a high level of security of supply. Under this scenario the total available capacity is 193.7 GW, which can serve as a sufficient reserve. There are also projections for the necessary reserve for various years and the calculation method is also disclosed in another National Grid study.[5] This study also demonstrates that in a period with low demand and high wind utilization rates wind production has to be constrained in order to ensure sufficient capacity reserves provided by gas-fired power plants.

Portugal produces a rolling five year network development plan every year, including limits on renewable capacity in each transmission network node, as well as investment costs and grid/interconnection upgrades and construction. The 2009 - 2014 Periodic Plan upgraded the overall renewable energy target to 5500 MW in 2011, for onshore wind capacity the target is 6100 MW for 2014, while the plan aims at 550 MW of offshore wind capacity for 2019.[6] The plan takes into consideration already completed investments, as a result of which between 2009 and 2014 less network investment would be necessary because of the newly built RES-E capacities.

[4] http://www.nationalgrid.com/NR/rdonlyres/CF7E564E-BD49-4E3B-B772-F1A908EE0059/57213/UKFutureEnergyScenarios2012.pdf

[5] http://www.nationalgrid.com/NR/rdonlyres/DF928C19-9210-4629-AB78-BBAA7AD8B89D/47178/Operatingin2020_finalversion0806_final.pdf mentioned formula at page 30, table at page 31

[6] Jorge Vasconcelos: Conceptualising Framework Conditions For The Role Of Renewable Energies And Their Integration Into The Networks

Since 1999 the Spanish TSO - Red Electrica de España (REE) – has been devising investment plans for longer periods, with a possibility of revision every year. These plans are quite similar to the Portuguese ones, including scenario assessments, costs and capacity estimations, with a detailed technical background. An investment plan published in 2002 for the period of 2002-2011 defined the maximum amount of power that can be injected per network node. It set an integration limit of 10.000 MW in peak periods, and a maximum 5.000 MW of wind capacity limit in off-peak periods. A revised plan was published in 2006, establishing measures on the technical requirements for wind power generation allowing for easier and more accessible balancing, which means that more capacity can be accommodated in the system. A study from 2006 shows that if 75% of the existing wind turbines are technically well-equipped, then the maximum allowable wind energy capacity is 14.000 MW for Spain, and 4.040 MW for Portugal.[7] The study also states that if all the turbines were well-equipped, then there would be no upper limit for wind power penetration in these two countries from the system side. It has to be noted, however, that a high penetration of wind power capacities could significantly increase the end-user prices.

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[7] Asociación Empresarial Eólica, "Wind power 2006," 2006. [Online]. Available: http://www.aeeolica.org
F. Rodríguez-Bobada, A.R. Rodrigues, A. Cenã, and E. Giraut, "Study of wind energy penetration in the Iberian Peninsula," in Proceedings of the European Wind Energy Conference & Exhibition (EWEC 06), Athens, Greece, 2006.

II. QUEUE MANAGEMENT

Background

The penetration of RES-E generation is often constrained by network connection, expansion or upgrade opportunities. The time requirement of permitting and installing RES-E generation units is, in general, significantly shorter than that for network expansion and upgrade required by massive new RES-E connections. It is also common that governments/regulators first put effective incentives in place (e.g. in the form of generous feed in tariff systems) to encourage new RES-E generation while regulators miss to create similarly effective remuneration schemes for transmission and distribution companies for their grid development efforts.

This asymmetry of incentives and the time lag between RES-E generation and network upgrade projects often results in competing investor requests (or *queues*) to develop certain renewable resources or to connect production facilities at given grid connection points.

Regulators can respond to such a situation either by providing generation developers a *non-constrained connection right* to the grid or by establishing, in cooperation with the network companies, connection capacity limits to the grid and develop an evaluation and selection methodology to grant scarce development and connection rights. This latter option is called *queue management*.

Providing non-constrained connection rights for RES-E developers might lead, under market and regulatory conditions favourable for these developers, to a very fast and excessive RES-E penetration that might compromise grid/system operation reliability either at the transmission or distribution levels. Therefore such a regulatory solution might be useful at the start-up phase of the RES-E industry but might turn out to be unsustainable in the longer run.

A more promising regulatory approach to manage competing investor requests is queue management. This will include the establishment of connection capacity limits and the development of the rules of connection capacity allocation. The regulatory background of queue management is better to be ready and published before the resource is opened for developers in order to avoid long queues and investor uncertainties due to unclear grid connection rules.

The following table summarises the major steps of the queue management process.

Table 1: A general scheme for the queue management process

	TSO	Regulator	Project promoter
1. Integrated resource and network planning	assessment of RES resources and their compatibility with network availability		
2. Technical capacity calculation	preferably by substation level		
3. Available connection capacity determination	taking RES policy objectives into consideration		
4. Publication of queue management rules	before resource is opened up for development		
5. Submission of porject/connection applications			
6. Screening	minimum technical and financial requirements	supervision, licensing	
7. Capacity allocation	a) first-come first served or b)first-ready-first-served or c) tendering	supervision, licensing	
8. Connection agreement			

Supply of connection

Queue management should start with the establishment of the available quantity of connection capacity. Here the first step is *connection capacity calculation* (see section 1). Based on network modelling, TSOs and DSOs should determine, preferably by substation or connection point, the amount of intermittent generation capacity (MW) that can be connected to their grid so that system reliability is not compromised. We can call it as *technical connection capacity* by substation.

> International experience demonstrates that the technical connection capacity of an existing transmission or distribution network is not a static number but largely depends on the pattern, flexibility and cooperation of generators and customers connected to the grid. Grid operators seem to learn about their capabilities to integrate intermittent producers only when they face increasing numbers of RES-E connections. See more on the dynamics in technical connection capacity in section 1.

How much of the technical connection capacity should be offered to RES-E developers is not a pure business matter of the grid company. Energy policy (or the Regulator) might wish to put a constraint on it in order to control the speed of RES-E penetration and the related support budget. This is why the decision on *available connection capacity* should be based on a consultation process between the grid companies and the Regulator, who could also make and publish a decision on the dynamics of available connection capacity over time. This will improve transparency and predictability for RES-E developers.

Demand for connection

When sufficient financial incentives are in place, developers will wish to enter the RES-E market by developing RES-E projects. Usually they will have to apply for several licenses / authorisations (building license, environmental license, etc.). A crucial one of these is the grid connection application. These applications make up the *queue* that has to be managed by the grid company.

We can distinguish the regulator’s and the grid company’s objectives with regard to the queue management process.

The regulatory objectives are:

a) to help meet RES-E policy objectives (e.g. quantitative RES-E capacity or consumption targets);
b) to promote the utilization of best quality RES resources;
c) to select best quality applications to ensure that what is licensed will indeed be built;
d) to minimize the cost of RES-E integration for end customers.

Additional related objectives of the grid companies are:

- to minimize the system security risk from RES-E connections;
- to minimize the profit loss of the company from RES-E connections (potential loss of related generation business if grid companies still own generation capacities; connection cost to be financed by the grid company; additional cost of balancing and reserves).

In order to meet regulatory objectives a) - b), grid companies have to be provided with sufficient financial incentives (see section 1).

Screening

Separating high quality from ‘junk’ applications is a central regulatory issue, since a connection license granted to a ‘junk’ investor can block future connections if the project is not built. Regulators, in cooperation with grid companies, can require grid connection applicants to meet minimum technical and financial standards (*screening*). Regulators might also issue a revocable development license that specifies the maximum allowed time to complete a RES-E project (similar to the *use it or lose it* principle). An additional tool that could be applied is requesting a deposit from project promoters.

Capacity allocation

When the demand (aggregate amount of applications) for RES-E connection at a given substation or connection point falls below available connection capacity, there is no connection capacity allocation problem for the grid company. The one that comes first can get the connection right.

However, when the demand for RES-E connection at a given substation or connection point exceeds the available connection capacity, a connection capacity allocation problem arises.

> Apparently, the demand for RES-E connection capacity at a given substation or connection point might depend on several variables, e.g. RES-E support level (+), RES resource quality – e.g. quantity and reliability of the source (windspeed, hours of sunlight)

(+), connection cost (-), quality of other infrastructures (+), cost of land use (-), etc. The grid company should carry out a thorough analysis of RES-E connection demand for its grid, especially at points with high RES resource quality.

Similar to capacity allocation methods in the context of transmission congestion, we can distinguish between administrative (*first-come-first-served, pro rata*) and market based (*tendering*) connection capacity allocation methods.

In case of *first-come-first-served* allocation, a connection capacity right is granted for free according to the temporal order of capacity requests received by the TSO until there is no further available connection capacity at the given substation / connection point. This kind of allocation can be considered as 'fair' but it is not efficient: the zero price of connection does not reflect the economic value of this scarce resource.

The *pro rata* allocation means that all requests are accepted but only partially as a fixed share of the total request and total available connection capacity. Capacity rights can be allocated for free or at a price. The price of the capacity in the latter case is not market based but determined by the TSO or the regulator on e.g. cost basis. This allocation mode allows for the strategic behaviour of bidders as they – knowing in advance that the required amount will be cut pro rata – ask for higher connection capacity than they are willing to use.

Another alternative to the *first-come-first-served* allocation scheme is the '*first ready, first served*' system.[8] Regulators could set up a system to monitor the advancement of an application and set up milestones in order to provide incentives to project promoters to finalise the connection process according to a pre-set schedule. In case the promoter cannot fulfil its obligations for a given period (milestone), the application will be cancelled, or placed again at the end of the queue of applicants. A further instrument in the hand of regulators is the application of a deposit system, in order to filter out 'junk' applications from the queue, as those applications could easily deter real promoters from project development.

A market based approach to connection capacity allocation is to call eligible applicants for an *open and competitive tender* for connection rights in case of excess demand. The outcome of a competitive tender will reflect the economic value of having the option to use a given MW of grid connection at a given time and location. Bids can be established on minimum $/MWh price support required by the developers or the share of connection cost the bidder is willing to pay for if winning the right. In this way competitive tenders can contribute to minimizing the support needed to meet RES-E policy objectives and thus help RES resource development at least cost for final customers. In addition, competitive tendering improves the transparency of the connection capacity allocation process and minimizes the scope for corruption.

For the above reasons we strongly suggest ERRA regulators to prefer competitive tendering to other schemes to allocate scarce RES-E connection capacity.

[8] Jennifer Heintz (2013), *Interconnection of new generation facilities*. ERRA presentation, Abu Dhabi.

RES-E connection capacity tenders can be designed, structured and executed in various ways. While the TSO/DSOs seem to be best positioned to manage competitive connection capacity tendering, the process should rather be developed and supervised in close cooperation with the regulator.

The following example summarises the queue management process for wind generation projects in Turkey.

In Turkey the queue management process for wind projects includes the following steps:

- The available capacity for connecting wind generation is published by the TSO (TEİAS).
- Wind power plant applications are forwarded to EMRA (Turkish Regulatory Agency) for these capacities.
- These applications are forwarded to TEIAS for studying connection opportunities.
- TEIAS gives its comment concerning the availability of connection capacity. If the application is alone in the substation, EMRA provides a license to the application.
- If there are multiple applications, the bidding process is done by TEIAS to determine the owner of the capacity.
- After receiving the license, the investor signs a connection agreement with TEIAS.
- The project will be approved by the Ministry of Energy and Natural Resources; after the realization of the project, a System Usage Agreement will be signed with TEIAS.

(Source: Presentation by Gül Okan & Nurhan Ozan 2011: *Planning for wınd and queue management*)

III. CONNECTION COST CHARGING

Background

The connection costs charged to renewable capacities should be transparent and proportional. Explicit rules must be guiding the TSO and DSOs in this field, in order to minimise their discretionary power, and ensure that objective conditions and tariffs orient the investors. Proportional tariff schemes ensure that applicants wishing to connect new capacities to the grid are paying their right share according to the costs arising from their development. This guarantees that market participants receive information on the true cost of their developments, so they can make the right investment decision. As the connection charge for renewable capacities could translate into high costs – mainly for wind farms, where connection cost can vary between 5-15 % of the total investment cost and even higher for off-shore wind - connection cost could be a decisive factor in the investment decision process and in site selection.[9]

In this context determining the connection cost of power plants has a twofold objective in guiding the RES-E investments:

- On the one hand it gives incentives to RES-E developers to choose the most suitable sites for their capacities, including the costs of connection. This could be an important factor for intermittent RES-E generation (such as solar, onshore and offshore wind), as the most suitable sites could be far away from consumption centres and from suitable network connection points, e.g. in remote mountainous areas and offshore sites. Additionally, these sites usually have fewer consumers in the neighbourhood area, thus reducing the incentives of DSOs to actively participate in these developments. This might bring about the differentiation of connection charges by territory. This is not the same as a fully differentiated nodal pricing system, where all nodes have a differentiated system tariff and connection charge. For example in case of the Italian RES-E auctions the connection charge is calculated for the given node, where connection is expected to take place, but also in the Turkish system in case of multiple application the charge will be differentiated by the applicants themselves in the bidding process. In Hungary, in the second wind development call (which was finally cancelled), applicants received differentiated points according to their siting decisions. (See the case studies for details).
- On the other hand the requests by developers provide extremely valuable information to grid developers (TSO and DSOs) to identify the locations with the highest demand for grid extension and where should they develop their network in the near future. TSOs can communicate these developments to the promoters in their network

[9] Cost range from Swider et al (2008): Conditions and costs for renewables electricity grid connections: Examples of Europe. in: Renewable Energy

development plans, which is compulsory to produce regularly for all ENTSO-E members (European Network for Transmission System Operators for Electricity) and suggested to all ERRA members' TSOs.

Present practices of European countries show that many countries promote RES-E developments through positive discrimination in grid connection charging of RES-E capacities in order to achieve a higher uptake of these technologies.

In the short run the main objective of the positive discrimination of RES-E is to help the early phase uptake of these technologies. The fulfilment of EU and national targets requires the speeding up of the early deployment phase of RES-E and one of the tools to achieve this is to ensure a cost advantage to them in case of connection charging. However, it must be clear, that if these advantages are only given to RES-E capacities, this could lead to less effective network development in long term, as it could distort the locational signal and could also excessively increase the burden falling on the end-consumers. So ERRA member states should carefully design their RES-E strategy with respect to the connection charging regime as well. As in most cases the purchasing power of consumers is much lower than in EU member states, an adequate decision could be to charge the full connection cost to RES-E developers in order to minimise the impact on the end-consumer prices. RES-E producers should only be privileged if the foreseen grid developments due to the new RES-E capacities are in line with the otherwise planned long term network developments.

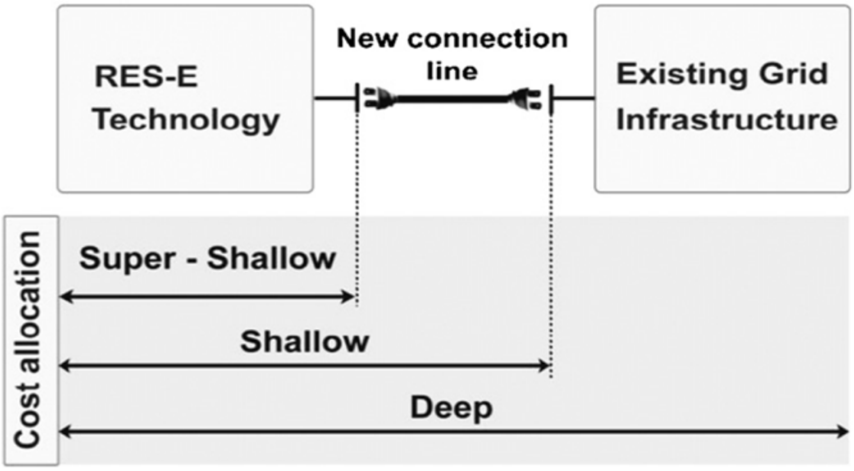
Cost allocation methodology

There are two basic methods and a combination of them for charging for the connection of RES-E capacities depending on the costs allocated to the developer. One is the *shallow cost charging regime*, when the project developer only pays for the new connecting infrastructure (including the line and some other infrastructure elements) to be built up till the point of the existing grid infrastructure. In this case the developer does not pay for any infrastructure upgrade within the existing network that might be needed in order to accommodate the changes necessary for the new plant. These extra developments of the public network will be paid by the system operator, and through the price regulation regime finally the end user will cover the cost of the upgrade through their bills. This process is called 'cost socialisation' and will be introduced in detail later. The other method is the *deep cost allocation*, when developers not only pay for the new connection line, but also for those network developments that are needed within the existing network behind the new connection point.

Two more solutions exist that are variants to the two principal ones described above. One is the *super shallow cost approach*, when the developer only pays part of the cost of the new connection infrastructure, or does not pay at all for the connection. This is definitely the advantageous for the developer, reducing its investment burden, but in turn end users have to pay the full price of the connection. There is another method; the *hybrid approach*, when the

RES-E developer pays the direct connection part of the new line, but only a fraction of the further development of the existing grid infrastructure behind the connection points. The next figure illustrates the first three options.

Figure 2: Approaches of RES-E grid integration cost allocation



Source: Swider (2008)[10]

Although the shallow cost approach distorts the 'locational signal' of the connection cost charge regime, and in the longer term this might result in less efficient network developments, it has a clear advantage. As the cost up to the connection point could be measured with higher precision than the costs of the reinforcement of the existing network, the developer and the network operator could estimate the cost accurately. The disadvantage is that if further reinforcement is needed within the existing network, the grid operator might overestimate the cost for the reinforcement, as its cost will be paid by the final consumers (see Swider 2008). Therefore tight regulatory cost control is needed to limit the price increase for consumers. Another disadvantage of the shallow approach is that it does not give incentives to DSOs to actively participate in the connection process. As DSOs do not receive the full cost of connection immediately, only with a delay through the regular price setting process that might take place 4-5 years later, they might prolong the connection process or even stop some developments. In some countries (see the Hungarian case study for an example), RES developers occasionally did not make use of their right for cost reduction in connection charging, but paid the full costs in order to elicit a more positive attitude of the DSO.

The main advantage of the deep cost approach is that it places the whole network development cost on the actor that generates the cost increase. Thus developers take into account their full 'external' cost to the network, and make their investment decisions accordingly. This process results in an optimal, efficient network development. The main disadvantage of this approach is that the reinforcement of the existing network generally

[10] Swider et al (2008), Renewable Energy (33)

creates positive 'externalities' to other users, e.g. consumers in the area, or latecomer RES-E developers, who do not have to pay for this reinforcement. This creates a 'first mover disadvantage' meaning that latecomer developers might be better off. This could make postponement a reasonable strategy for developers, which goes against the ambitious plans of the EU concerning RES-E targets. One solution to this problem is that the regulator/network operator reimburses part of the connection charge if new developers use the new network element. This solution was applied in Greece and in Hungary, but the process poses challenges to the regulator to develop a fully transparent allocation method (Green-Net-Incentives (2009)). *Another disadvantage of the solution is that it might discourage new entrants.*

Another, more recent solution has been applied in Denmark and the UK for offshore wind development, but in its nature this rather belongs to the shallow cost method. In these countries network operators overcome the cost allocation problem by building the core network until 'connection zones', where new developers only pay the cost of connection till the edge of the zone, as the rest is ready built. In Denmark the Danish Energy Agency opens tendering procedures for these zones, where applicants compete for connection through lowering their expected feed-in–tariff (FIT) level. In this way both the connection charging and queuing problems are solved, as bidders always have a merit order by which the applicants could be selected.

The essence of the hybrid approach applied in some countries (e.g. Czech Republic) is that network operators under the control of energy regulators determine the fair share of network developments driven by RES-E penetration, and the total cost of this network upgrade is allocated to developers according to their capacity size. This could be done ex-post, based on actual upgrades, and ex-ante based on network development plans. Both methods involve uncertainties, as ex-post evaluation could be unpredictable for RES developers, while ex-ante methods might not reflect the exact cost levels of future developments. The same solution, namely the close cost control of the regulator is also needed in order to avoid overspending in network developments.

The suggestion for ERRA member states is that the shallow cost approach should be used only for a few years in the early phase of RES-E penetration, and subsequently changed to the deep cost charging approach before more sizeable RES-E developments take place. In addition, if DSOs have a discretionary role in this process (e.g. due to the lack of detailed regulation of certain elements) the shallow cost approach might trim their incentives to actively participate in this process.

Design issues

Besides the main cost sharing decision (deep vs. shallow) there are important 'design' elements that need to be addressed when the connection cost regime is developed. These tasks mainly concern the regulators and the network operators (TSO and DSOs if they are also involved) and they include the following items:

- The method of cost socialisation. The network development part, which is not paid by the RES developer, will be paid by the end consumers – this allocation method is called cost socialisation. The general way to allocate these costs is through the regular cost and price review of the network companies to determine the system use charges. Regulators should keep a close control over these costs, they should check if these costs are eligible/justified and reflect the necessary costs of upgrades, as network operators have little incentives to keep them low. Another design question is the base of cost socialisation: the costs could be spread over all consumer categories, or some of them could be exempted. E.g. Germany exempted large energy intensive end-users from paying for RES-E developments, while Hungary exempted households.
- Lump sum or yearly payments of connection charges. Although it seems plausible that the connection cost should be paid in the year of connection, it could also be paid in annual instalments during the whole lifetime of the line. Some countries use the second approach, e.g. in the UK connected plants pay the capital component of the connection through an annualised payment during the whole lifetime (40 years) calculated on a pre-determined allowed return rate (6%). This cash-flow element to be paid is determined in advance and known to the developer.
- Connection charge differentiation according to voltage level (high, medium or low voltage). Not only do the technological characteristics of the connection differ according to the voltage level, but the network operator is also different. In case of medium and low voltage usually the DSOs are responsible for grid development and maintenance. DSOs might possess completely different incentives and roles in the whole process, so distinct rules might be applied to them. E.g. in case of the micro-generation of households and small scale applications their role should be limited to check the technical requirements of the application, and once that is fulfilled, connection should be granted without any discretionary decision of the DSO. In case of commercial sized RES-E plants, DSOs have a role in determining the optimal connection point for the developments to minimise overall costs, but they are less concerned about higher level system related issues - such as reserve requirements - which will be the handled by the TSO.
- The option of own construction. A good regulatory practice in many countries (e.g. Italy, Greece) is to allow RES-E developers to carry out the connection works themself, if they judge the network operator’s pre-determined or estimated cost level to be too high. After the line is built by the RES-E developer in compliance with the required technical standards, the general solution is to transfer the ownership (and maintenance duties) to the network operators. If this is the case, the parties also have

to agree on the right purchase value of the asset. This value has an important implication for the network operator, as it will serve as the basis for the regulated asset base calculation.

- Existence of compensation mechanisms. In case a deep connection charging approach is applied, it is important to pre-set the compensation mechanisms for the developers. If a new plant is connected to the system using an already financed existing network element, reimbursement of some of the cost to the developer of that network piece may be considered, as this would solve the first mover disadvantage problem mentioned earlier. This system will only work if transparency and proportionality in the reimbursement process is ensured, otherwise the system might hinder some of the players and open the way for unnecessary disputes and legal cases (the time-period of cost sharing should be limited for practical reasons).

IV. DSO INCENTIVES TO INTEGRATE DGS

Background

The 20-20-20 objective of the European Union sets compulsory renewable energy targets for the member states. The overall energy targets are translated to heat and electricity targets in the National Renewable Action Plans (NREAPs) submitted by the countries. Renewable electricity targets are fostered by state subsidies provided for RES-E in all countries via production supports (feed-in tariffs, feed-in premiums or green certificates), investment supports and preferential grid access. As a consequence, the volume of RES-E production and capacity has increased considerably in the last decade. Even though the subsidies have been cut in many member states (especially for PV), the falling costs of technology are likely to drive the penetration of these technologies further. Setting RES-E targets is not a unique feature of EU member states. In 2010 the countries of the Energy Community started a formal process of adopting legally binding targets for 2020.[11] According to the renewable energy survey of ERRA countries (conducted by REKK in 2011) out of the 24 countries 20 have both RES and RES-E targets and an additional two countries have either one of the two, leaving four countries without any RES or RES-E targets (Nigeria, Serbia, Ukraine and Albania). Studies suggest that wind and PV will reach grid parity within a decade, after that penetration will decouple from state subsidies, that is RES-E deployment will gain speed even in the absence of generous subsidies. The integration of RES-E (and distributed generation in general), however, will remain a major issue as large scale deployment of distributed generation (DG) on the distribution grids requires major network investments and hence impacts the cost borne by DSOs.

This section is devoted to the effect of large scale DG deployment on the financial status of DSOs and explores ways to provide stronger financial incentives[12] for them to facilitate the ambitious RES-E policy goals in a way that minimises the overall network cost.

It is important to denote that the issue of integrating renewable units on a large scale cannot be treated separately from the issue of converting today's passive distribution grids to smart grids which are believed to be able to deliver the required network services at a lower cost.[13]

The impact of large scale DGs on network investment and operation

The integration of many DG units requires major investments to the distribution networks as the network needs to be designed for peak RES-E production. This means that the DSOs have to upgrade the network so that it can deliver electricity securely even when all intermittent

[11] For the proposed target figures see: IPA Energy at al. (2010): Study on the Implementation of the New EU Renewables Directive in the Energy Community

[12] Administrative barriers are not discussed here.

[13] For a comprehensive analysis for the UK see: EA Technology: Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks, 2012

producers are operating at their peak power ("fit and forget approach"). Therefore this traditional network management paradigm requires that the network is configured to peak generation capacity after each additional DG unit and the peak generation that is not consumed at the distribution level is transferred to the transmission level. The International Energy Agency estimates that the investment needs in the European distribution network - including the replacement and the modernisation/smartening of existing assets in order to be able to serve a growing electricity demand and new requirements (smart grids) – amounts to 480 bn EUR up to 2035.[14]

Apart from the increased CAPEX, the DSOs are likely to confront changes regarding the level of distribution losses due to DG penetration.[15] The sign and rate of change is very network specific, however some rules of thumbs can be defined. Distribution losses might increase or decrease depending on the location of load and DG generation. In case of geographic overlap losses often decrease due to the consumption of locally produced electricity instead of electricity transported from further centralised generation units. However, if the DG penetration reaches a level where it leads to an increased volume of reverse power flow (i.e. from the DG towards the substation) then energy losses will also increase.[16] The concrete level depends on the grid topology, including the location of generators and loads. As experience with high DG penetration is still scarce, this level is not determined yet, and this process will take place in the ERRA member states with a significant delay compared to EU members. As far as operational costs are concerned, the operation of a more extensive network results in higher OPEX.

An alternative solution to simple network capacity extension is to gradually develop the distribution system to become "smarter" in physical terms (i.e. network assets), enabling the transformation of the distribution network into an automated network similar to the transmission grid. Active network management is indeed real time management taking into consideration the load and generation characteristics of the network users. It brings about higher asset utilisation and the integration of electricity storage options. In this case less capacity expansion is needed due to higher levels of grid utilisation (as a result of real time data) and the active management of DG units (DSM), however adding the ICT (infocommunication technology) element to the network involves considerable investment. Distribution losses, ceteris paribus, are lower than in passive networks due to better load-generation optimization but they start to increase above a certain penetration level. In other words, higher losses appear only at a higher penetration level. The operation costs are likely to increase due to active management.

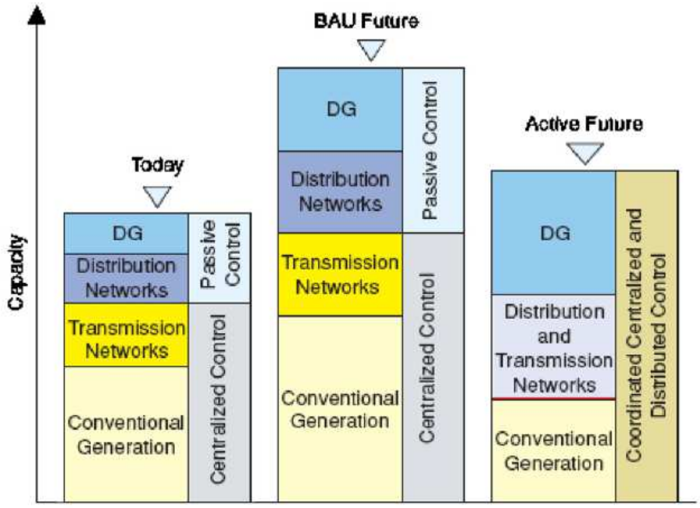
[14] IEA: World Energy Outlook 2010

[15] Here we only refer to physical losses and exclude commercial losses (theft).

[16] Fries, Gomez, Cossent and Rivier (2009): Improvement in current European network regulation to facilitate the integration of distributed generation, Electrical Power and Energy Systems 31, pp.445-451 and Joode, Welle and Jansen (2007): Business models for DSOs under alternative regulatory regimes (DG-GRID)

In sum, DSOs face increased costs due to 1) the additional investment into network assets that are not designed for the integration of generation units, 2) the higher volume of energy losses after a certain level of penetration, and 3) operational expenses associated with the large scale penetration of distributed generation, including RES-E. Quantitative analysis shows that the profit of DSOs is negatively affected by the penetration of DGs except in some cases of low penetration (below 15-20%) and high concentration.[17] Under these circumstances, DSOs have limited incentives to actively facilitate the integration of DGs on a large scale. It is important to mention that most of the ERRA countries are far below this level, nevertheless they should be aware of the problems associated with massive RES-E deployment.

Figure 3: Active vs passive management of distribution networks



Source: Djapic, 2007

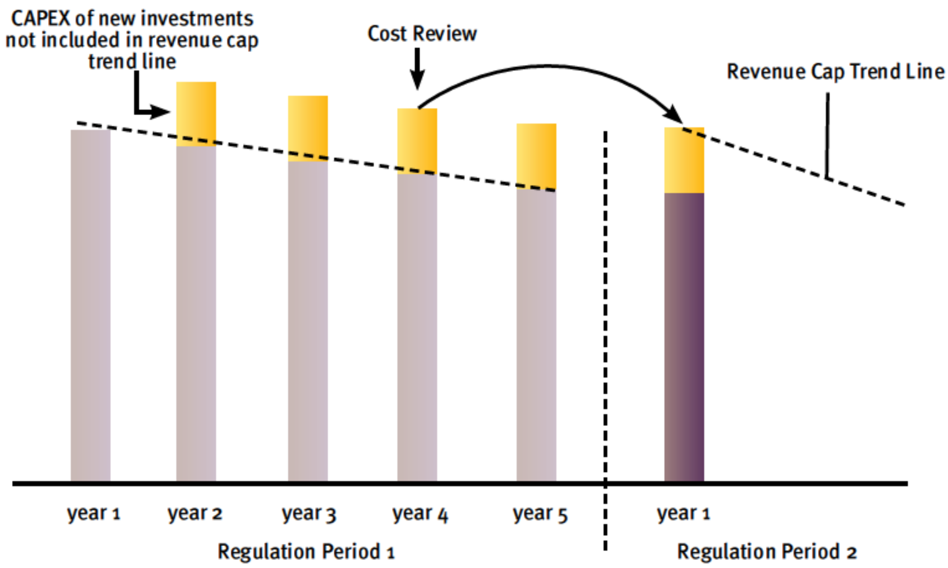
The current mainstream DSO regulation

DSOs are natural monopolies and – according to the EU legislation – they are at least legally and functionally unbundled from the rest of the electricity supply chain. Being a natural monopoly, pricing of network use and access to the network calls for regulation. The traditional rate of return regulation has been substituted in most countries with performance based regulatory regimes (or incentive regulation) that is focused on the promotion of efficiency in distribution activity. The regulator caps the revenue (or price) ex ante for the whole regulatory period and provides incentives to DSOs to improve their efficiency as the saved costs remain with the DSO until the end of the regulatory period. Another major feature of a standard incentive regime is that it involves a predicted productivity development (X factor) that can be unique to the DSO or the same for all DSOs in a country. The allowed revenue for each subsequent year is reduced with this percentage (declining revenue cap trend line in figure below). The eligible cost – that is the basis of network tariffs – is assessed at the

[17] Joode, 2007

end of the regulatory period and it is the starting revenue volume in the subsequent period. This system provides a strong drive for the DSO to maximize cost savings so additional regulatory measures are usually taken in order to maintain the quality of service. These are incentives and penalties associated with the major subfields of the quality of supply such as continuity of supply, voltage quality and commercial quality.

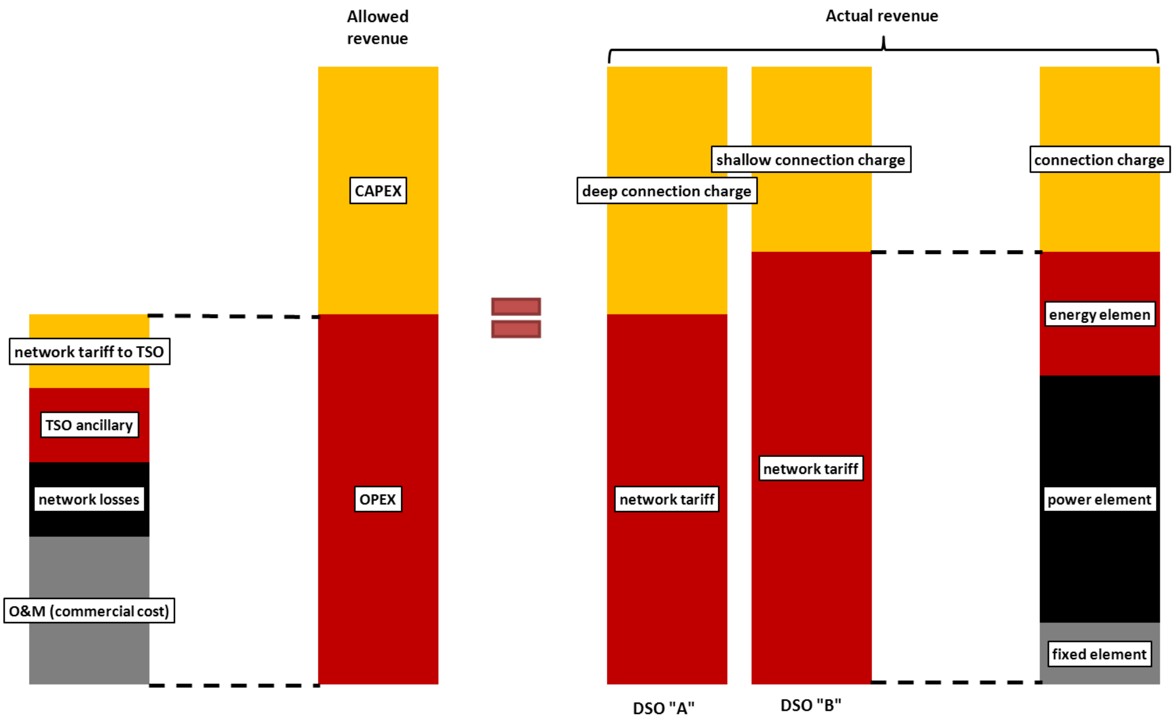
Figure 4: Revenue cap regulation



Source: EURELECTRIC, 2011

The business model of DSOs consists of two sources of revenues and various cost elements, as shown in the following figure.

Figure 5: DSO business model



Source: REKK

Network pricing consists of 3 main regulatory steps. First, the total allowed revenue is determined which includes the operating expenditures (OPEX) and the cost of capital that includes depreciation and interest. The depreciation method and the rate of return that the DSO is allowed to earn on its capital investments in network assets (such as switchboards, transformers, cables, meters etc.) are decided by the regulator. OPEX covers various cost elements such as:

- network and ancillary system charges paid to the TSO,
- procurement cost of network loss, and
- operational and maintenance cost, including the cost of metering and billing (commercial cost).

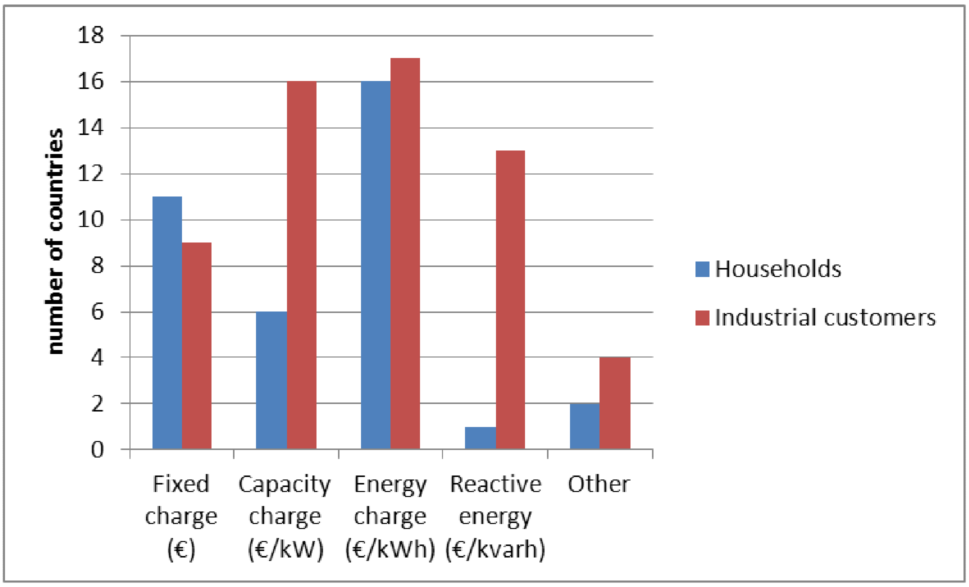
As a second step, network connection charges are defined. These costs are country specific and they are often categorized according to the share of the cost borne by the connecting generation unit versus the DSO (see in section 3). The remaining allowance is then the amount that needs to be covered by network tariffs (use of network charges). Connection charges and network tariff hence are interrelated: the share of grid reinforcement cost that is not covered by the cause of the cost (generation unit), is socialised across the network users (in most countries they are the electricity consumers) via the network tariff.

The rate scheme – as the third step – allocates the network cost among the different users. The schemes are country specific, the potential major dimensions for differentiation are:

- consumers and/or producers (who pays?)
- consumption pattern (load profile) and size (by fuse) at each voltage level
- geographical areas and voltage level (network structure)
- time (peak versus off-peak).[18]

The current European network regulation is characterized by the predominance of flat rate volumetric network tariffs (€/kWh) for households, and the mixture of power demand charge (€/kW), reactive energy charge (€/kVArh) and fixed charge (e.g. €/month) for industrial consumers (Figure 6). The energy charge is – in half of the 17 countries covered by the EURELECTRIC survey – coupled with a fixed charge component for households but capacity charge is not a common tariff element.

Figure 6: Network tariff components in selected European countries for households and industrial customers



Source: EURELECTRIC, 2013

In sum, for households – where the majority of DG is likely to be installed converting these consumers to "prosumers" – the distribution network cost is primarily driven by power demand but revenues are mainly based on the amount of energy consumed (volumetric).[19]

[18] EURELECTRIC: Network tariff structure for a smart energy system, May 2013
[19] Prosumers are customers that consume electricity from the public network but also produce electricity to the network. The actual consumption status (consumption minus production) changes in every second.

Network pricing in the context of large scale DG penetration

Current network pricing models need to be adjusted in order to provide adequate incentive to DSOs to integrate distributed generation (RES-E units). The major problems with the current regulatory schemes are that

- the cost of DSOs are driven by power demand, as they have to secure the line for peak demand hours, but their revenue is based on the total energy demand,
- there is a time lag between the network investment and its inclusion in the revenue cap (CAPEX time shift problem),
- the investment recognition in cost review is uncertain,
- network tariffs are not paid by the actors that generate these costs: producers in general and prosumers in particular,
- flat rate volumetric tariffs do not reflect the marginal cost of network use (peak versus off-peak).

Even during the periods when the majority of distributed generation units (PV and wind) are off-line, the network must be able to cover peak demand in order to maintain the continuity of supply. Electric vehicles might even add to this peak demand, if their consumption is not adequately shifted towards periods of low load by dynamic electricity tariffs. With high DG penetration the network usage time (ratio of energy consumption and peak power – kWh/kW) for consumption from the public network is likely to decrease (depending on the volume of new demand sources associated with low carbon energy systems such as electric vehicles and heat pumps).[20] This leads to a decoupling of revenues and costs within the regulatory period as network tariffs are kept constant through the period. Due to the volumetric structure of tariffs, tariff revenue decreases with lower consumption (due to prosumers), at the same time the integration of the very same actors requires network investments and higher operational costs (ancillary services, voltage control etc.). This deters DSOs from connecting renewable units to their network and regulatory effort is needed to overcome this deployment barrier (see suggestion later).

Another issue affecting the remuneration of DSOs within the regulatory period is the time lag between the investment and its inclusion in the revenue base. In our example an investment activated in year 2 translates into earned cost only 4 years later (Figure 4). This stems from the fact that in classical incentive regimes the revenue base in not adjusted within the period. Such a time lag results in the reduction of the real (discounted) allowed rate of return.

A few other tariff related problems exist that are not directly associated with the remuneration of DSOs but affect the overall cost of providing adequate network services in the future. Once a considerable share of consumers convert to prosumers, the overall network cost will be

[20] EU Low Carbon Roadmap 2050

spread over a smaller customer base because electricity consumers pay the network tariff on the basis of their net consumption. This means that the network costs caused by DG owners will be financed by ‘ordinary’ consumers: tariffs increasingly decouple from costs (lack of cost reflectivity). On the other hand, the flat/static network tariffs do not reflect the marginal cost of network use that varies with the utilisation level of the network (congestion). Network users are not incentivised to consume electricity during low demand periods that would enable the reduction (more moderate increase) of peak network capacity. Half of the countries surveyed by EURELECTRIC have launched some form of time-of-use (ToU) network tariff for certain consumer segments but the mainstream tariff scheme in Europe is featured by static energy charges.

The above mentioned problems call for the consideration of several possible regulatory solutions. The network tariff schemes can be redesigned in a way that network costs and the derived benefits are better matched within the consumer base either by moving towards deep connection charges (see section on connection cost charging) or by expanding the network tariffs to generation as well. In addition, time-of-use network tariffs paid by both consumers and producers would provide signals to all network users towards minimizing the overall cost of maintaining an adequate electricity grid. The main concern of DSOs, their adequate revenue that covers costs and provides a fair rate of return, can be met by introducing a capacity element to the network tariff (Table 2). On the other hand, the substitution of the energy tariff with a capacity tariff is likely to reduce the incentive of the customer to save on overall consumption: (s)he is induced to stay within the capacity limit (not using all equipment at the same time) but without a constraint once under this upper limit. The incentive is better in case of the ToU network tariff scheme that is used in Denmark (real time pricing). Some other European countries apply interruptible load tariffs (CZ, DE, ES, GR, NO, PT and SE) or direct load control (CZ, DE, FI, FR and NO).[21] However it is important to note that if both electricity and network price is time dependent, then – as they are driven by independent factors - they might cancel each others’ impact. All options, apart from A in Table Table 2 below (Fixed volumetric tariff), reduce peak demand and as such reduce network cost.

[21] EURELECTRIC, 2013

Table 2: Overview of different network tariff options

		impact on overall energy consumption	impact on network cost reduction	revenue adequacy for the DSO
A	Fixed volumetric tariff (€/kWh)	++	+	+
B	Time-of-use volumetric high peak (€/kWh) low off-peak (€/kWh)	+++	+++	+
C	Fixed capacity based tariff (€/kW)	+	+++	++
D	Time-of-use capacity based tariff (€/kW)	++	+++	++
E	Two part tariff energy component (€/kWh) capacity component (€/kW)	++	+++	++

Source: based on EURELECTRIC, 2013

Summarising the network tariff option we can conclude that the fixed volumetric tariff scheme prevalent in Europe for households needs to be reconsidered to provide an incentive to DSOs to integrate DG as required by national and European policy targets. The introduction of capacity tariff elements seems to be an adequate solution, however, in its fixed form it provides weaker incentives to save electricity. ToU capacity tariffs, on the other hand, might be alien to consumers accustomed to simple schemes. Moreover, the impact of their interaction with ToU electricity prices is not straightforward. Concerning countries with less ambitious RES-E targets (or currently low penetration level) and lacking sophisticated metering infrastructure (smart meters able to handle ToU tariffs), the maintenance of the existing ToU tariff systems based on radio controlled or twin meters (e.g. Hungary or Serbia) is essential to keep the already achieved consumption shift to hours of low load. Adequate regulatory incentives could include – apart from the introduction of capacity tariff elements – some form of extra remuneration for DG units connected to the system. The application of deep connection charges would provide safeguards against the extra cost falling on DSOs in relation to building new connections, but it can also create a barrier for RES-E penetration.

Revenue adequacy can be assured even in case of volumetric tariffs (A and B) if the incentive regulation is not practised in its classical form but includes mechanisms that reduce the CAPEX time lag. Some countries – for example Italy and the Czech Republic – employ a hybrid regulation: rate of return regulation on capital costs and incentive regulation on OPEX. The rate of return regulation provides a strong incentive to invest, however the typical pitfalls of this regulation must be considered (overinvestment). Another option is to include extra elements in the incentive regime to induce investments. Germany, for example, introduced the so called “enlargement factor” and the “investment budget”. The first is to cover changes in the DSO requirement to supply consumers (e.g. demand changes), while the latter is to compensate for network restructuring.[22] Since 2010, the enlargement factor encompasses the number of connection points for distributed generation (e.g. wind and photovoltaic) and it is

[22] WIK-Consult: Cost Benchmarking in Energy Regulation in European Countries, 2011

meant to cover the costs of network extensions at the DSO-level in order to connect an increasing amount of RES-E.

In 2005 OFGEM in the UK reformed the price cap regulation for the grid to trigger extra investments to facilitate RES integration. This was especially important as – also in this regulatory package – the deep connection charge was substituted with the shallow charge regime.[23] DSOs were able to recover their grid related connection and integration costs of RES generation upfront through the network tariffs by an incentive payment per $kW_{DG/RES}$ connected (2.16 €/$kW_{DG/RES}$ (singular) and 1.44€/ $kW_{DG/RES}$/yr (annually)). This payment was even higher (4.3 €/$kW_{DG/RES}$) in case of innovative network solutions for the first 5 years of operation in the framework of Registered Power Zones (pilot power zones housing innovative network solutions). In addition, DSOs were allowed to use 0.5% of their annual revenue on innovative investments (covering DG generation connections as well) and spread a significant share of their cost among consumers (Innovation Funding Incentive: IFI).[24]

Another form of supporting DSOs in taking up the risk of investing in innovative technological solutions is the co-financing of such projects from public funds. In the UK, the Low Carbon Network Fund, opened in 2010, disburses £500m to support DSO funded projects experiencing with new technology, as well as commercial arrangements to meet the challenges posed by the future low carbon economy of the UK. The fund enables the DSO to recover a proportion of its expenditure on small project (first tier) and sponsors bigger, 'flagship projects' on the basis of an annual competition (second tier). In the first year, 4 flagship projects were awarded £63.6 million and 11 projects were registered under the first tier, focusing on low carbon and energy saving initiatives such as electric vehicles, heat pumps, micro and local generation and demand side management (including smart meters).[25]

Similar R&D funding is available in Italy for research centres and universities but also for network operators. The costs are financed by the tariff payer (RSE presentation, 2011). As an example, the biggest distributor, ENEL is about to finish its 4 pilot programmes (Interregional Operational Program - POI) in the 4 Southern regions (Campania, Calabria, Puglia, and Sicily) hosting a bulk of wind and PV development to be able to integrate them. The program consisted of "traditional" grid reinforcement but involved a substantial smart grid element as well. The project is expected to result in a MV network that is able to integrate PV plans between 100kW and 1 MW.[26]

Apart from the targeted R&D budget, the Italian regulator (AEEG) employs an *input-based incentive regime* for DSOs to start smart grid demonstration projects.[27] An expert panel

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[23] Prior to 2005 producers paid deep, while consumers paid shallow connection charge.
[24] DG-GRID, 2007
[25] http://www.ofgem.gov.uk/Networks/ElecDist/lcnf/Pages/lcnf.aspx
[26] Michele de Nigris (2011): Italy's smart grid programmes and projects in an international context, presentation – Bologna, 8th June 2011
[27] Resolution ARG/elt 39/10

selected eight projects from the proposals submitted by DSOs. The projects had to meet several requirements in order to receive the 2% extra WACC in addition to the default return that is the incentive payment guaranteed for 12 years.[28]

The UK network regulation (both for electricity and gas and for distribution and transmission) referred to as RPI-X has been assessed and reformed in 2010 and OFGEM is now introducing a new regulatory framework called RIIO. The RIIO defines output incentives for service delivery.

In sum, RES-E production is supported by public policy both on the production (feed-in tariffs and green certificates) and the grid side, the latter in the form of preferential grid access and cost sharing. Beyond a certain level of penetration (not unrelated to the decrease of technology costs) the major social costs will not any more register on the production side (overall support paid to RES-E producers), but they will be network related due to the conversion of the traditional distribution grid into intelligent systems. As a result, the socialization of these network costs becomes contestable.

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[28] Lo Sciavo et al (2012): Changing the Regulation for Regulating the Change - Innovation-driven regulatory developments in Italy: smart grids, smart metering and e-mobility (http://www.iern.net/portal/page/portal/IERN_HOME/ICER_HOME/ABOUT_ICER/Distinguished_Scholar_Award_2012/Winners/ICERaward_ChangingRegulation_final.pdf)

Adequate DSO network planning and operation to accommodate renewable connections

Connecting renewable generation to the low and medium voltage network level poses various challenges to the DSOs. First, connection of RES-E could create network operation problems due to the intermittent nature of many RES-E generators (wind and solar). As they are mostly non-dispatchable capacities, due to their technical conditions and to the regulatory framework (priority dispatch), it pose challenge for the DSOs to meet the stochastic demand in their control area.

Second, as more RES-E developers could demand connection in a concentrated area, the resulting demand for connection could easily exceed the maximum available connection capacity of the given zone.

Third, RES-E developers might request connection on remote areas that are optimal from the resource availability point of view, but would be placed in locations where the grid is underdeveloped or inexistent (e.g. rural, mountainous areas).

Fourth, more intensive RES-E developments would require more active network planning and operation from the DSO side, than their present conventional network management practices. E.g. DSOs usually operate on their control area medium load and low voltage lines, characterised by a radial structure and one-directional electricity flow (in the direction of consumers from larger side generators). In these conventional systems monitoring of consumption does not require very sophisticated control, while with the spread of more distributed RES-E generation requires more intensive monitoring and control of the system. The flow of electricity could become bi-directional, measuring must be more frequent and automated. DSOs in their conventional role might lack the necessary expertise and technology to carry out these activities.

These challenges require more sophisticated network development planning and operation from the DSO side, similar to the operation of TSOs. DSOs have to be more active in monitoring the network activities, and they have to be more accurate in the planning phase and also in granting connection right to the RES-E developers.

DSOs can follow basically three different approaches in the process of planning/connecting/operating RES-E plants in their control area.[29]

The first, most conventional approach is the '*Fit and Forget Approach*', where the DSOs plan their network capacity to the theoretical maximum load that can appear in the given network node. By receiving a RES-E application, they estimate individually the change in the peak

[29] More details could be found in the Eurelectric report: Active Distribution System Management, 2013. http://www.eurelectric.org/media/74356/asm_full_report_discussion_paper_final-2013-030-0117-01-e.pdf

load that can occur at the given line, and build or reinforce the line to that estimated level. If they do so, they can 'forget' about any arising problems later, as the system will be maintained secure, so no congestion or voltage level problem is likely to occur in the future operation. The problem of this maximum security is that someone has to cover the significant reinforcement/construction costs that occur. If the deep cost allocation method is applied for the connection costs (see chapter III on connection charges for details) than the RES-E developer will pay for these costs, which could mean significant burden on the developer and could prevent the construction of the plant and the connection infrastructure. If the shallow approach is applied, DSOs will take the extra burden of constructing the line, which will be socialised in the following regulatory period. The Fit and Forget approach has the advantage that it needs low flexibility and supervision from the DSO side, so the network can operate very securely without too much intervention. But it has the disadvantage, that it might need significant infrastructure investments. At low level of RES-E penetration this might be viable option, but reaching significant RES-E shares can lead to very high costs for the DSOs.

The second approach is the *Reactive network integration* or '*only operation*' approach. In this process DSOs have to admit all RES-E capacities that apply for grid connection. All the problems that would arise later will be solved during the operational phase: if the network cannot handle the electricity to be injected than the injected volume of certain operators, including RES-E units, can be curtailed on the basis of pre-negotiated conditions and compensation. Generally this approach is applied in forerunner countries of RES-E, such as Germany and Italy. As wind and solar capacities are generally built earlier than the supporting grid infrastructure, RES-E producers sometimes have to face production curtailments in order to prevent congestions or outages. As RES-E producers have priority dispatch rights in these countries, they are compensated for the lost production. Similar approach was applied in the Czech Republic during the high uptake of PV plants in 2009-2010, but the practice was stopped by the regulator by the request of the TSO, which became concerned about possible network capacity problems.

The third approach is the *Active distribution system management*, where the various phases of the grid connection process: planning, connection and operation takes place in an integrated manner and with a very sophisticated supporting IT infrastructure. Integration means that network planning is not exclusively carried out by the DSO, but the other affected parties - the TSO and RES-E developers are also involved in the process. In addition RES-E plants take part in the ancillary service market as well, providing higher flexibility to the system. Consumers are also included in the active network management, through activating flexible load options on their consumption. Network reinforcements and loads are optimised, which means that it can be a more economical option of increasing the connection capacity of the grid, without too much investment in the physical infrastructure. Through the utilisation of 'flexibility platforms', the DSOs can procure the necessary flexibility from the RES-E plants (or more generally from any Distributed Generation (DG) plant) or from the consumer side as well.

In the following we introduce those good practices that could DSOs follow in managing their RES-E connections. We go through these practices following the four main steps of the DSOs in the process[30]:

- preparatory activities - including the network planning activities of the DSOs
- administrative procedures to reach an agreement between the DOS and RES-E developers for the actual connection points
- physical works: network extension or network upgrade
- operation of the extended network with the RES-E plants.

In the network planning phase DSOs make sure that the network will be operated safely in the long term without congestions and voltage problems. Two good practices are presented by Eurelectric (2013) that can help the DSOs in a more efficient network planning. One example is the *coordinated network development*, where the DSO deals with network expansion/reinforcement applications in a coordinated manner. Instead of deciding on each application on an individual basis - which might lead to a non-optimal network development - applications are collected within a pre-defined timeframe, and then DSOs consider the requests within the same package. This would help the DSO to more optimally design its grid development. One example is the Spanish 'Evacuation Board' process, where an authority of the administration collects and validates the request before sending it to the DSO/TSO concerned. The other example is the Italian 'open season' process, where applications are collected within pre-defined time periods.

Another example of a more active network planning is the *group processing approach* of Ireland, where the TSO/DSO concerned first creates groups of the applications, and then designs the necessary network development for the group as a whole. DSO will share the costs of the development between group members according to the activated capacity size.

During the administrative procedure to reach an agreement between the parties, the DSO could request the developer to sign a *variable network access contract* if the regulation allows the application of this option. This means, that the DSO will have the right to curtail the RES-E producer in few hours in a year in order to prevent excessive load on the grid. By applying this contracting form, the existing network would be able to accommodate significantly more RES-E connection. A German example (EWE NETZ) shows, that allowing 5% curtailment in a year could more than double RES-E capacity connection possibilities in the assessed network (Eurelectric 2013).

[30] More deatiled description can be find on the ERRA website on the Potential regulatory incentives for DSOs simplifying the connection process for distributed generators to the DSO network by Zoltán Lontay (forthcoming)

The previously described approaches, together with the option to enable consumers to participate in the peak load shaving on a tendering/competitive basis would enable the DSOs to operate the existing network in a more efficient manner, and to reduce the pressure for excessive network upgrade or extensions.

Another solution applied in some EU countries and in the USA as well to enable RES-E integration in areas without grid infrastructure is the creation of Renewable Energy Zones (REZ). In these zones the electricity infrastructure (transmission lines, substations) are constructed prior to the development of RES-E in order to facilitate their network integration. Their characteristics are the following:

- Prior network infrastructure development in the given zone.
- Financing through public money, which is recovered generally through tariffs in the electricity bill. This solution requires substantial political support for the scheme.
- There is a pre-set and announced maximum connectable RES-E capacity at a given location.
- Actual connections are usually granted through a tendering procedure in order to enhance competition for the given site and reduce cost burden on consumers.

The actual examples for such developments are the Texas Competitive Renewable Energy Zones, and the Denmark offshore grid developments: e.g. Anholt Offshore Wind Farm. In this zone Energynet.dk (the TSO) is responsible for establishing an offshore substation, the export cable to shore and the connection to the main high-voltage power grid on land.[31] The cost of the infrastructure development is than 'socialised' to the end consumers.

Network planning is a critical issue in this case as well, as the Danish experience shows. Strict geographical delimitation of REZs, as well as timing of the construction is important as well. As REZ are located in geographical areas with scarce available information available on the site, the first steps are usually to carry out an EIA and a preliminary assessment of the site. The aim of the assessment is to determine if the creation of the site is in the interest of the community, who will later on finance the infrastructure through their electricity bill.

Most ERRA member states are in an initiating phase of their RES-E development, and DSOs are characterised by the Fit and Forget approach in their network management. DSOs in ERRA countries aiming to achieve higher RES-E uptake in the near future should try to apply first the more economical options in their network management systems before engaging in full Active distribution system management, as it requires more financial resources, expertise and time. These more economical options include the coordinated network development or group processing approaches. Creating REZs would also require significant financing need, and price increases through the cost socialisation process, so they are not recommended for ERRA member countries with lower purchasing power. In their case application of the deep

[31] source: http://www.dongenergy.com/anholt/EN/Projectbackground/Pages/default.aspx and http://www.ens.dk/node/3206/procedures-permits-offshore-wind-parks

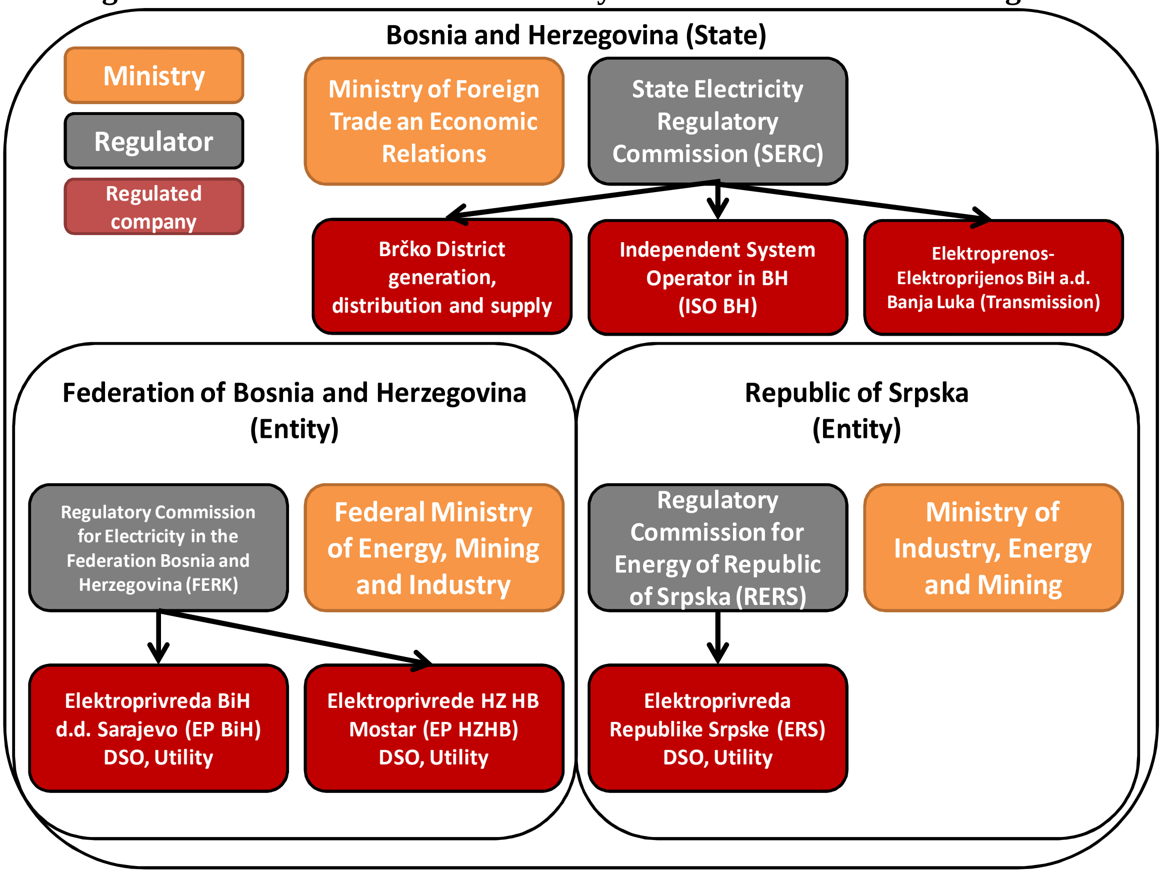
connection charging regime could also help to avoid excessive investments in the grid infrastructure developments.

V. CASE STUDY – BOSNIA AND HERZEGOVINA

1. Brief country description

Bosnia and Herzegovina (BiH) is made up of the two fairly autonomous entities of the Federation of Bosnia and Herzegovina and the Republic of Srpska and a smaller administrative region called Brcko District, administered by a local government. Due to this division, administration and other activities are shared among regional and state bodies. Moreover, regional entities usually have more jurisdiction and influence than state ones. No common energy strategy exists on the state level, but the entities have already worked out strategies on their own: in the Federation of BiH, a strategic plan of the energy sector development until 2020 has been adopted and finalized by 2009, while in the Republic of Srpska an energy strategy setting goals until 2030 has been accepted by the legislation in early 2012.

Figure 7: Stakeholders of the electricity market in Bosnia and Herzegovina



On the state level, the Ministry of Foreign Trade and Economic Relations has jurisdiction over policy making in energy-related issues. However, it has not produced any strategic document so far, entities have stronger incentives and are more active in this field.

In 2004, the independent system operator was established (ISO BiH). The company is jointly owned by the two entities. The ISO manages and balances the transmission system, and organises cross-border capacity auctions. The transmission network is owned and maintained by Elektroprenos BiH, also jointly owned by the two entities. The ISO and the transmission company are regulated by the State Electricity Regulatory Commission (SERC).

On the entity level, three regional, vertically integrated utilities produce, distribute and supply power to end consumers. These utilities own the majority of coal mines in the country, the generation fleet of the bigger thermal and hydro capacities, the distribution grid and the supply companies. EP BiH and EP HZHB are active in the Federation of BiH, regulated by the Regulatory Commission for Electricity in the Federation of Bosnia and Herzegovina (FERK). ERS operates in the Republic of Srpska, monitored by the Regulatory Commission for Energy of Republic of Srpska (RERS).

By the end of 2012, 3964 MW of generating capacity was connected to the grid. Generating capacities are either hydropower plants or lignite fuelled thermal power plants. Since 2005, thermal power capacity displayed a slight decrease of 200 MW, whereas two hydropower plants have been commissioned (Mostarsko blato 60 MW, Peć-Mlini 30 MW). Wind power has not been installed yet, although 300 MWs are under construction. In 2012, SERC reported the first solar capacities to be connected to the grid.

Annual power production and the utilisation of thermal power stations are highly dependent on current hydrological conditions. BiH has been a net exporter of electricity since 2005, the volume of exports depends on hydro production – for instance, in 2010 net exports nearly reached 4000 GWh, whereas in the following year the same indicator barely approached 1500 GWh. Distributed generation in small hydro plants, industrial CHPs and solar power plants amounted to 166 GWh in 2012, a mere 1% of total power production.

Due to the large share of hydro generation, renewables are abundant in BiH, accounting for 50% of the capacities and 30-50% of production. Nevertheless, we must note that new capacities have been added really slowly: since 2005, only 90 MW of hydro and some solar has been commissioned, wind power investments are lagging and have not been connected to the grid yet. Strategic targets for RES integration on the state level do not exist yet. In the Republic of Srpska, the 2011 decree of the Ministry of Industry, Energy and Mining set the targets for renewable generation until 2020. However, a study by IPA for the Energy Community assessed the possible target for various Balkan states, including BiH. It concluded that to reach the indicative target set by EU Directive 2009/28/EC, BiH should produce around 27% of its electricity from renewable sources. According to IPA estimates, this means a hydro production of 6 TWh and onshore wind production of 0.5 TWh. The strategic documents of the entities both survey the potential and one even carries out scenario analyses, but do not set any goals.

Total SAIDI and SAIFI indicators are exceptionally high, SAIDI amounting to more than 700 minutes per consumer per year, SAIFI around 8.5 incidents per customer per year. As for a comparison, unplanned interruptions did not exceed 150 minutes in Slovenia, Austria, the Czech Republic or Hungary.

Table 3: Length of the high voltage grid in Bosnia and Herzegovina, km

	2005	2006	2007	2008	2009	2010	2011	2012
400 kV	992	992	865	865	865	865	865	865
220 kV	1691	1691	1526	1526	1525	1525	1525	1525
110 kV	3649	3649	3889	3889	3888	3888	3889	3889
110 kV cable	31	31	31	31	31	32	32	32

source: SERC

Table 4: System adequacy indicators in HV and MV networks

		BA		RO	HU	SI	AT	CZ	TR	IT
	2010	2011	2012	2009	2010	2010	2010	2010	?	2010
SAIFI	10.04	9.07	8.53	6.5	1.63	1.81	0.66	1.78	?	2.27
SAIDI	742.87	459.32	729.96	682	132.59	81	31.77	135.88	?	88.84

Source: CEER, SERC

2. Determining the maximum connectable renewable capacity

Methods to determine the maximum connectable renewable capacity

According to the Grid Code of May 2011, the ISO defines the maximum capacity of wind power allowed to be installed to the grid. Capacity values are published in the network development plan (Indicative Plan of Generation Development). The current plan of 2014-2023 sets the limit at 350 MW. 120 MW of these capacities is located in the Republic of Srpksa, 230 MW in the Federation of Bosnia and Herzegovina. Wind power has not been connected to the grid yet, but projects with a capacity of 276 MW were approved by the network owner Elektroprijenos BiH and the network operator ISO BH, connection for all these capacities is expected by 2014.[32] Although a feed-in tariff system of reference price plus premium exists (with exceptionally high prices of 200-400 EUR per MWh for wind and PV generation), current tariffs in the Federation of BiH were judged as invalid by the Consitutional Court.

A study surveying the network infrastructure and grid conditions conducted by Economic Consulting Associates (ECA), EIHP and KPMG helped to determine the maximum amount of wind power to be installed. Network models were used to assess the impact of wind power integration on the current and the future grid, determining the maximum amount to be installed without jeopardizing system security. Wind power was added to potential points of connection, and maximum capacity was determined for the whole grid. The study concluded that this amount is at most 150 MW, requiring minor network improvements. Integration of

[32] These dates of commissioning should be observed with caution: although most of these projects were announced already in 2010, expected to be completed by 2011, no wind farms have been commissioned so far.

300 MW is only possible if major network investments on the 110 kV main lines are realised. So far these investments have not taken place, but the ISO is ready to connect 350 MW of new generating capacity.

No such limit for intermittent PV capacities was set.

Present practices of ISO

Using a network model the ECA analysis identified 6 scenarios of wind power investments, and quantified the corresponding investment need as well as the additional reserve quantity.

Table 5: The impact of wind investments in Bosnia and Herzegovina on reserves and network costs

	WPP installed (MW)	Current network	Additional secondary reserves (MW)	Network investment cost
Scenario A	150	feasible with minor investment	104	~1 mEUR
Scenario A1	200	feasible with medium investment	?	~3.6 mEUR
Scenario B	300	feasible with major investment	217	~11 mEUR
Scenario C	600	not feasible	397	~22 mEUR
Scenario D1	900 (concentrated)	not feasible	490	~44 mEUR
Scenario D2	900 (dispersed)	not feasible	500	~29 mEUR

source: ECA vol. 3 pg 28; ECA vol. 1 pg 31

New network development is financed through the network tariff paid by users of the grid and the fixed part of the connection fee paid by the user connecting to the network (connection rules art. 20).

When installing wind power, the need for balancing increases. The current regulation does not take this phenomenon into account yet, since no intermittent generation exists.

The ECA study quantified the need for additional secondary and tertiary reserves. Depending on the amount of wind power to be installed, 100-500 MW of reserves are needed on the secondary level and 250-330 MW on the tertiary (ECA vol. 1, pg 78).

Daily schedules need to be submitted on D-1 between 10 a.m. and 2 p.m. The schedule may be re-adjusted 120 minutes before realisation, but the ISO has the right to refuse the adjusted schedule. It seems that scheduling does not hinder renewables.

The role of the regulator in the process

According to the Connection Rules set by the regulator (SERC), the regulator itself has to accept the maximum amount of wind capacities, proposed by ISO BiH.[33]

3. Queue management

No queue management practices exist currently.

4. Connection charge regime

The present connection fee regime does not offer incentives to connect new generating capacities. All costs are incurred by the generator, and the developers of new capacities are required to finance additional investments (deep charging regime).

The power plants connecting to the transmission system need to pay the direct and indirect costs as well. The connection fee is made up of two parts, a fixed and a variable part. The fixed part is a multiple of a regulated fee per MW, while the variable part is determined ex ante by project analysis. If the costs of the ex ante calculation were exceeded by more than 5%, the user shall pay the additional costs.

Renewables and small hydro (≤10MW) get a discount from the fixed part of the connection fee, they only have to pay 50% of this item. Payments related to the variable connection fee are the same as in case of the other technologies. Connection fees are paid once, upon joining the grid.

Only the Transmission Owner is allowed to build the connection, and it will own the newly constructed lines. (Connection rules art.18)

Entity regulators determine the rules of connection. Connection fees are set by regional DSOs and approved by entity regulators.

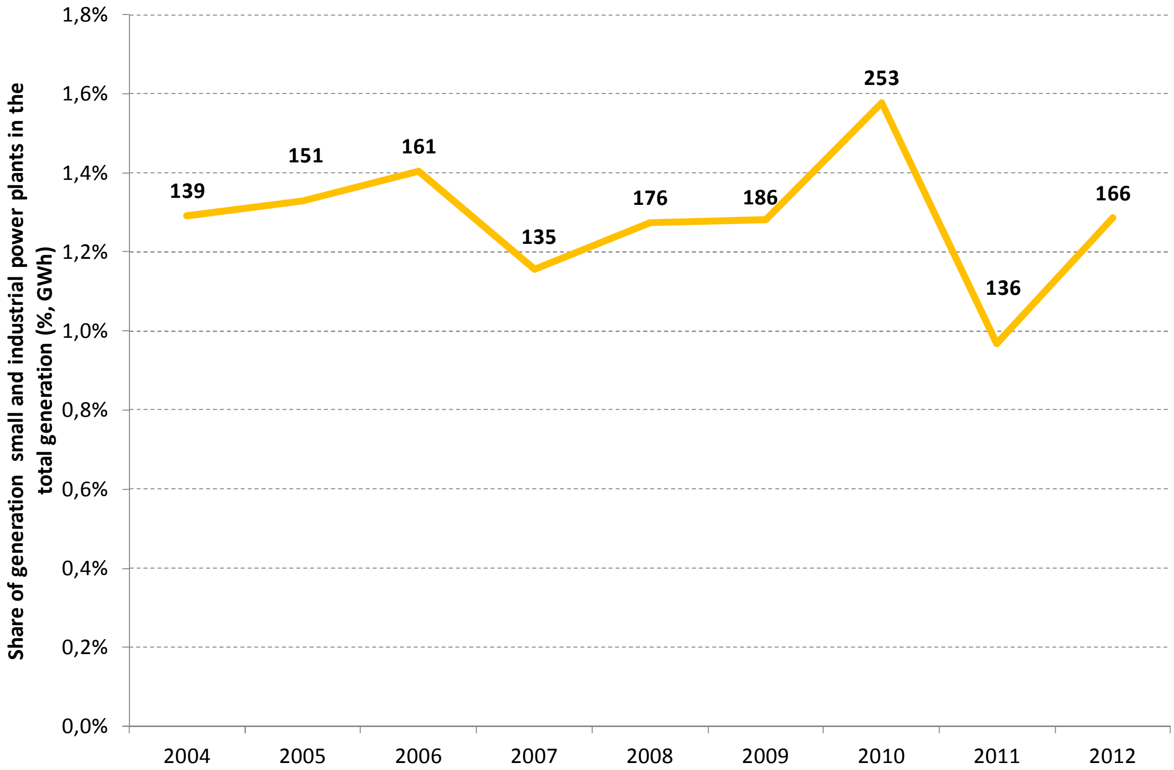
5. DSO incentives

General issues

Around 1-2% of the total consumed electricity was generated in distributed and industrial power plants. Capacity data is not available, but the generation data suggests that no significant development has taken place in distributed generation (since it closely follows the trend of overall production).

[33] http://www.derk.ba/DocumentsPDFs/Pravilnik-o-dopunama-Pravilnika-o-prikljucku26Jul2012-en.pdf

Figure 8: Share of distributed generation in Bosnia and Herzegovina (%, GWh)



source: SERC

The regulatory environment driving DSO activities

The DSOs, the ISO and the Transmission Company are all regulated based on traditional Rate-of-return regulation. Prices for the ISO and the Transmission company are adjusted irregularly, upon request. DSOs are also regulated irregularly and upon request.

Presently applied incentives for DSOs to actively participate in distributed generation

The network tariff for final consumers is made up of four parts:

- Capacity charge: Users pay a fixed monthly fee for the maximum capacity they used in the billing period. Peak capacity is metered on a 15 minute basis for large consumers, while households pay a fixed capacity charge.
- Active electricity: consumers pay for their metered consumption on a monthly basis.
- Excessively taken reactive electricity: reactive power is measured for most users, or metered occasionally at the request of the DSO. Excessively taken reactive power is the difference between metered reactive power and reactive power calculated from active power assuming a phase angle of 0.95. The price is always the peak tariff.
- Fixed compensation per measuring point: if the network user has more than one connection point, it is compensated through a fixed monthly fee.

Final consumers of electricity pay for the use of the network. The cost of ancillary services and transmission network usage is determined by the SERC, these fees are paid by high voltage network users. These costs are passed on to final consumers. Regional DSOs may cover these costs by billing them to final consumers, this is supported by the regulation. Producers do not pay for using the network.

Role of the Regulator/Ministry in the process

The regulator sets the network tariffs based on a rate-of-return methodology.

Key findings

1. Bosnia-Herzegovina is a country with excess electricity production, and a high share of hydro in its generation portfolio. Therefore presently there is modest demand for further RES-E developments, the country only explores these options.
2. Consequently, RES-E developments lag behind, although 270 MW of licences have been approved for wind based generation. According to available information these projects are rather immature, with project promoters trying to obtain the licences in order to sell them to ‘real’ investors with sufficient capital to realise the projects. However, due to the numerous uncertainties in the market investors are rather hesitant to realise these projects: information, a stable regulatory framework and subsidies are absent. The shared responsibilities of the regulatory bodies (country and entity level) increase both the administrative burden and time need of licensing, also contributing to the increased uncertainty amongst potential new entrants. The court decision that suspended the operation of the renewable support fund created obstacles for further RES developments. The uncertainties in the regulatory environment not only postpone RES-E developments, they also extend the planning and construction of traditional power plants.
3. In summary, Bosnia and Herzegovina is in an early phase of RES-E development and due to the lack of regulatory and political drivers, this situation might be prolonged in the near future.

VI. CASE STUDY – ITALY

1. Brief country description

For the last few years Italy has experienced one of the fastest expansions of renewable energy based power production. Both onshore wind and solar capacity growth is significant, with photovoltaic power as the driving force of this expansion. While in 2011 the total installed solar capacity was more than 12700 MW, at the end of the first trimester of 2013 the capacity exceeded 17000 MW.[34]

Italy employs a quite complex support system for RES-E generation. There are different incentive schemes, and there have been sequential changes in the regulation in the last few years. Until January 2013 there has been a Green Certificate system for plants with more than 1 MW of capacity, but for power plants commissioned after that date this option is not available. From 2013 they can choose from a simple feed-in tariff, or FiT set through a tendering process. The operators of smaller plants can choose from two kinds of feed-in-tariffs[35] and a premium tariff. For PV plants there is a separate incentive scheme, a premium tariff system called "Conto Energia". It has been changed several times due to tariff reductions, and lately a budgetary cap has also been set: the tariff is available only as long as the indicative cumulated yearly cost of the incentives stays below € 6.7 billion.[36] Net metering is also a possibility, but for small plants only (below 200kW) and only in place of the above mentioned tariffs. For wind and solar plants a tax reduction system is also in force, but a few limitations have been added recently.[37]

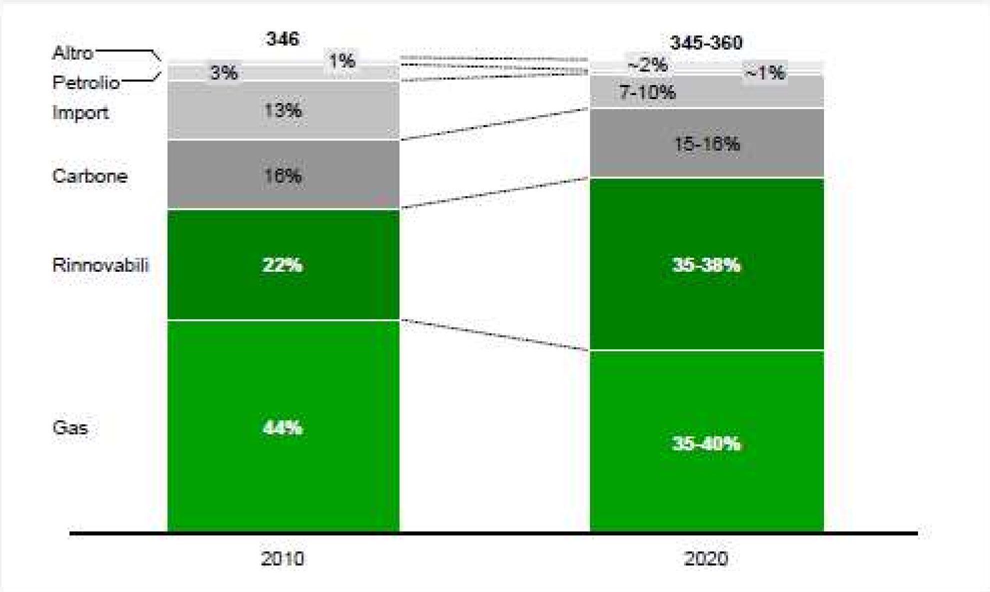
Italy submitted the NREAP (National Renewable Energy Action Plan) to the EU in 2010, and adopted the National Energy Strategy (SEN) in 2013 which replaced the 20 year old previous strategy. FigureFigure 9. shows the targets set in SEN for electricity production.

The renewable production target set for 2020 has almost been reached already in 2012, when total renewable power production was 93 TWh, close to the 100 TWh target. There are some 2020 targets first set in the NREAP[38] that Italy has already reached in the field of installed capacity: the planned capacity of hydro and solar power plants is 17.8 and 8.6 GW, while hydro capacities already reached 21.7 GW by 2011, and total solar capacities exceeded 17 GW in 2013. Geothermal plants are also on the right way: 728 MW out of the planned 920

[34] http://cleantechnica.com/2013/04/19/italy-now-has-16-7-gw-of-installed-solar-pv-capacity/
[35] Ritiro dedicato which is more of a regulation of the sale of electricity, and tariffa onnicomprensiva, which is only directly accessible under a set size – differentiated by fuel-types – while above that size the plant should be listed in a register with capacity limits set for each year.
[36] According to Cleantechnica research in April 2013 € 6.6 billion has already been reached
[37] http://www.res-legal.eu/search-by-country/italy/tools-list/c/italy/s/res-e/t/promotion/sum/152/lpid/151/, http://www.pvgrid.eu/database/pvgrid/italy/national-profile-7/commercial-systems/2514/commercial-pv-systems-1.html#3
[38] NREAP – National Renewable Energy Action Plan http://ec.europa.eu/energy/renewables/action_plan_en.htm

MW was already on in 2011. The growth of wind plants is more moderate, the target is 12.7 GW for 2020, and in 2011 only 6.9 GW was online.

Figure 9: Electricity mix forecast of Italy (MWh, %)



Source: National Energy Strategy[39]

According to CEER unplanned SAIDI in 2010 was around 100 minutes and unplanned SAIFI was around 2.25[40] including all events.

Italy plays an important role in the Mediterranean area thanks to its beneficial geographical position. It is a net importer, 13% of the electricity was imported out of a total consumption of 348 TWh in 2011.[41] The country is strongly interconnected with its neighbours: 4240 MW of interconnector capacity with Switzerland, 2650 MW with France, 630 MW with Slovenia, 500 MW with Greece, 220 MW with Austria, 900 MW „within the country" with Sardinia and another 1000 MW is under construction with Montenegro.

These interconnection lines are also important when we come to the topic of RES-E generation. With a high rate of intermittent capacity (in 2011 25% of total electricity production came from intermittent power plants), it is essential to own the necessary amount of cross border capacity to be able to balance the system. There are also agreements with neighbouring countries on data sharing about grid status and on MEAS (Mutual Emergency Assistant Services), both of which help the TSO to keep the level of security of supply high despite the above mentioned rapid RES-E capacity growth.

[39]http://www.sviluppoeconomico.gov.it/images/stories/normativa/20130314_Strategia_Energetica_Nazionale.pdf

[40] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/CEER_5thBenchmarking_Report.pdf

[41] http://www.terna.it/LinkClick.aspx?fileticket=1CZB7x2rHrU%3d&tabid=784

In Italy the transmission system operator, TERNA, owns and operates the system since 2003. The independent market operator GME (Gestore dei Mercati Energetici SpA) operates the future and spot market. GME acts as a central counterparty in the transactions, except the ancillary market where the TSO takes this role. The spot electricity market consists of a Day-Ahead Market (MGP), an Intraday Market (MI) and an Ancillary Services Market (MSD) where the TSO is the key player for balancing the system real time (GME website).[42] The Authority for electricity and gas market regulation is AEEG (Autorità per l'energia elettrica e il gas). In the distribution sector, Enel Distribuzione is the largest operator with an 86% market share, the rest is divided among several smaller companies (Lo Schiavo, 2012).

2. Determining the maximum connectable renewable capacity

In Italy there is no explicit capacity limit for grid connection: work required for the integration of an additional unit is automatically considered during the connection application process. As a result, grid operators cannot reject connection requests claiming that the network is unable to handle more generation units at the given location. As Italy is one of the European countries with the highest RES-E penetration, it serves as a good example for the integration of RES-E to its system.

Italy faces the typical problem of South-European countries: the most suitable places for RES-E power plant installation are far away from the densely populated parts of the country, so electricity as a rule has to be delivered from one part of the country to another. Balancing is also difficult, because PV and wind plants are mostly located in the South, while hydro capacities used as reserve are mainly located in the North (Alps). An additional frequent problem is that at the places of production the network is not perfectly developed yet, it needs further improvements. So not only is local construction needed, but - to avoid congestions while transporting electricity - an overall system development is also required. To show a few relevant examples, in Terna's Strategic plan (2011-2015)[43] a € 400 million investment is mentioned for connections to the grid and debottlenecking in the South, and in ENTSO-E's Ten Year Network Development Plan 2012[44] a similar development plan is included.

In order to reduce the magnitude of imbalance caused by intermittent generation, the regulator introduced an incentive system under which intermittent RES-E generators over 10 MW receive a payment that is inversely proportional to the absolute volume of the difference between the actual and programmed production.[45] Wind farms are required to install data collection systems to allow for the TSO to monitor production in real time.[46] A centralised wind forecasting system has been integrated into the TSO day-ahead and realtime market software to improve prediction in the system dispatch (Lo Sciavo, 2012). For plants under 10

[42] http://www.mercatoelettrico.org/En/Mercati/MercatoElettrico/MPE.aspx
[43] http://www.terna.it/default/home_en/investor_relations_en/strategy_en/strategic_plan_2011_2015.aspx
[44] https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2012/
[45] Res 05/10
[46] Art 13-16 Annex A Res 05/10

MW GME provides an aggregated forecast at the market area level based on a satellite-assisted metering system, which collects primary source and generation data of about 5,000 units. In addition, the TSO is financially motivated to provide good wind forecast.[47] As an outcome, lost wind production decreased from 10.7% (2009) to 5.6% (2010) of total wind electricity production at the transmission level, while at the same time installed capacity grew from 4851 to 5850 MW (Lo Schiavo, 2012).

The reduction of imbalance should also be assisted by the intraday market. According to the GME website the Day-Ahead Market opens 9 days before delivery day and closes 9 a.m. at D-1. The Intraday Market was introduced in 2009 and today it consists of 4 sessions with different closing times: two at D-1 and the other two on the day of delivery. Balancing Market scheduling also consists of 5 sessions. But RES-E producers do not participate in the intraday market, their gate closure is 9 a.m. at D-1, concurrent with the closure of the Day-Ahead Market. After gate closure, GME is responsible for the balancing of RES-E production deviations.

The participation on the reserve market is mandatory for every enabled production unit of every dispatchable and programmable power plant with more than 10 MW capacity. TERNA's Grid Code[48] requires these plants to guarantee at least a ±1,5% off effective power dedicated to primary regulation. Within the secondary reserve market RES plants with more than 10 MW capacity are excluded to this rule.

3. Queue management

Queue management issues need to be considered separately for auctioning and for the rest of the processes.

As a general rule, in case of the auctioning system no special queue management tool is required, as the TSO can order the applications to the given connection point based on the price offered in the bid. In other words, it can sort the capacities that intend to connect to a given connection point taking into account the capacity limits and the best prices offered.

For the rest of the processes system operators applied various techniques. One technique was to ask developers to pay 30% of the total connection cost payment in advance to ensure that better prepared projects get connected faster, and a special bank guarantee linked to technical milestones was also introduced a few years ago. This latter instrument has been abandoned due to the resistance of producers (see details in section 4.3).

In areas where too many connection requests were received - mainly in the Southern part of the country - the TSO introduced a scheme to more effectively manage the requests. An 'open

[47] Art 5 ARG/elt 351/07 "Determinazione della remunerazione dell'attivitŕ di dispacciamento dell'energia elettrica e definizione di meccanismi di premi e penalitŕ ad incentivazione della societŕ Terna S.p.A. nella medesima attivitŕ"

[48] http://www.terna.it/default/home_en/electric_system/grid_code.aspx

season' rule was applied, according to which developers could submit applications only during a given 2-3 months long period of the year.[49] After that the TSO is in a position to organize connections more easily equipped with all the required information at once before a new 'open season' starts.

4. Connection charge regime

Allocation methods

Italy employs a shallow cost regime for network connections. The cost of connection consists of three elements: an application fee, a connection fee and the cost of testing the operation of the connection (HV and EHV connections involve a further cost element that is the fee for the development of the technical solution). In the case of renewable energy sources, the grid operator bears the costs for expanding the grid.[50] For the last few years the importance of the application fee, as a cost component, has increased. The TSO introduced the above mentioned - quite high - application fee (30% of the connection cost) to filter the projects in order to preclude the capacity reservation of projects that will not be implemented and would only block those RES-E developments that would be realised if they were granted access to the grid.

The connection fee for RES-E (and high efficiency cogeneration) at low voltage (LV) and medium voltage (MV) levels is defined by two formulas[51] that both depend on the unit capacity, the distance to the connection point and the type of cable (air or underground).

Present practice

There were two major changes in the recent past: the regulator has introduced the above mentioned application fee, and at critical grid sections it has requested an additional bank guarantee of 20 150 EUR/MW for high voltage, 60 000 EUR /MW for medium voltage and 110 EUR/kW for low voltage grid connections. The applicant loses the application fee if the plant is not built by deadline. This tool – although supported through the consultation process – was abandoned due to the resistance of producers. The court has suspended the respective AEEG resolution no. 125/10.

RES-E applications for connection to the transmission or distribution grid must be given priority treatment and renewable energy plants must be given priority connection. A plant operator applying for connection enjoys priority grid connection even if that requires a grid expansion. RES-E plants are subject to lower connection fees than plants fuelled by conventional sources (25%).[52]

[49] http://www.autorita.energia.it/allegati/docs/10/125-10arg.pdf
[50] res-legal.eu
[51] see details in Articolo 12 in http://www.autorita.energia.it/allegati/docs/10/125-10arg_allA.pdf
[52] see details in Articolo 12 and 13 in http://www.autorita.energia.it/allegati/docs/10/125-10arg_allA.pdf

The regulation allows the applicant to carry out the connection works on its own (instead of the grid operator) for MV, HV and EHV connection. This option is used frequently by the applicants, because this way they can often save time and money even though it requires the cooperation of the DSO/TSO in providing the technical specification of the grid section (Eclareon, 2011). For LV connections only the DSO is allowed to execute the connection works. The grid operator is obliged to prepare connection cost estimates even when the applicant carries out the works. In this case, following the construction of the connection the TSO reimburses the money spent by the RES producer to construct the power line, and it becomes part of the TSO's assets.

The lead times for getting grid connection are the following:[53]

- about 6 months if the HV station exists;
- about 6 months if the HV station does not exist and the RES producers decide to plan and pay for the TSO's power line;
- about 24-30 months if the HV station does not exist and each actor (TSO and RES producer) plans and pays for his own power line.

Generally the cost of connection is a one-time fee. In addition, the operators of small sized household RES-E installations are obliged to pay an annual fee per connection point to cover the grid operator's administrative costs (15-30 EUR).

The cost of the grid expansions is passed through to consumers. According to the data of AEEG[54], there are different tariff packages. A few of them include fix fees – for example for every metering point –, but most of them only include €/kWh fees based on monthly consumption, or the maximum kW that can be used (with more diverse categories than LV/MV/HV).

There is a different incentive system in force for small sized, household installations (FIT). Various limits are applied: 60 kW installed capacity for a wind plant, 200 kW for biomass, 50 kW for a hydro plant. Small scale RES-E generation from these kinds of plants is directly eligible for FIT.

Similar positive discrimination applies to small PV units. The authorisation procedure of residential rooftop plants of up to 12 kW is rather simple – although this number dropped from 20 kW as a consequence of Conto Energia V[55] –, insofar as it does not require landscape permit, and the plant operators can choose from FiT (Conto Energia) or Net-metering. Since 2007 the commercial segment (until 200 kW) has also enjoyed the option of net metering but

[53] Ecorys (2010) Non-cost barriers to renewables – AEON study, Italy
[54] http://www.autorita.energia.it/it/prezzi.htm
[55] http://www.pvgrid.eu/database/pvgrid/italy/national-profile-7/residential-systems/2503/residential-pv-systems-1.html#5

normally the Single Authorisation Procedure is required with all its associated problems. Commercial operators can choose from the same incentive schemes.

5. DSO incentives

There has been a huge increase in the number and capacity of renewable power plants in the last few years. The most rapid growth has taken place for PV generation, between the end of 2011 and the first trimester of 2013 capacity grew by more than 33%.[56]

Italy employs a hybrid regulation for DSOs. There is a rate of return system for capital costs – they are post-financed by the consumers, while the OPEX part of DSOs' costs is financed through a price-cap regime covering four years.

Generally only consumers pay the network tariffs. The only exceptions are the above mentioned small power plants. As it was already reported, the elements of the tariff depend on the type of the tariff package. Some includes fixed fees, some only energy fees with capacity limits in some cases.

Dedicated R&D support is available both for research centres and universities but also for network operators. The costs are financed by the tariff payer (RSE presentation 2011). As an example, the biggest distributor, ENEL is about to finish its 4 pilot programmes (Interregional Operational Program - POI) in the 4 Southern regions (Campania, Calabria, Puglia, and Sicily) hosting a bulk of wind and PV development to be able to integrate them. The program consisted of 'traditional' grid reinforcement but involved substantial smart grid elements as well. The project is expected to result in a MV network that is able to integrate PV plans with capacity between 100kW and 1 MW.[57] Apart from the targeted R&D budget, the Italian regulator (AEEG) employs an *input-based incentive regime* for DSOs to start smart grid demonstration projects.[58] An expert panel selected eight projects from the proposals submitted by DSOs. The projects had to meet several requirements in order to receive the 2% extra WACC in addition to the default return that is the incentive payment guaranteed for 12 years.[59]

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[56] http://cleantechnica.com/2013/04/19/italy-now-has-16-7-gw-of-installed-solar-pv-capacity/

[57] Michele de Nigris (2011): Italy's smart grid programmes and projects in an international context, presentation – Bologna, 8th June 2011

[58] Resolution ARG/elt 39/10

[59] Lo Sciavo et al (2012): Changing the Regulation for Regulating the Change - Innovation-driven regulatory developments in Italy: smart grids, smart metering and e-mobility (http://www.iern.net/portal/page/portal/IERN_HOME/ICER_HOME/ABOUT_ICER/Distinguished_Scholar_Award_2012/Winners/ICERaward_ChangingRegulation_final.pdf)

Key findings

1. Italy is one of the leading countries in promoting RES-E developments. Its extraordinary growth in RES-E based electricity generation is not only fuelled by the high level of subsidies, but network connection related issues are also regulated on a very progressive way.
2. What is a distinct characteristic of Italy is that the TSO and the DSOs play a very active role in the connection process. Grid operators have to expand the network beyond the connection point if RES-E developments require it. In addition, for small RES-E plants the TSO has the mandate to produce production forecasts, and the regulation gives incentives to the TSO to increase its precision in forecasting. The costs, cost sharing and the deadlines of the connection process are regulated in detail, leaving less discretionary power in the hand of grid operators. This creates high certainty amongst investors in the field of RES-E developments for both the new entrants and for the operators of the already installed plants.
3. Italy is one of the few countries in Europe that applies an advanced form of RES subsidies: auctioning the potential connection points to new entrants. In this way the most economical option - requiring the lowest level of subsidy - is selected for each connection. This not only reduces the financial burden, but also helps the connection process and queue management. This type of auctioning is demanding for the regulator which needs to determine the connectable capacity and the exact connection point. The regulator has to possess all necessary information on grid status (grid modelling) and the local RES-E potential (electricity system modelling) in order to carry out this process effectively. Starting this year Italy also introduced a total budgetary cap on RES-E subsidies, but there is little experience on the actual results of this decision.
4. At the same time, the regulation is demanding on the developer side, too: developers have to pay 30 % of the connection fees in advance (to help screen for realistic, viable projects), and with the exception of micro-generators RES-E plants have to participate in the reserve market as well (regulability).
5. A central R&D fund is available to cover the expenses of research centres and grid operators in carrying out pilot programs in the field of distributed generation. This helps grid operators to assume an active role in exploring the opportunities offered by distributed electricity generation.

VII. CASE STUDY – HUNGARY

1. Brief country description

The Hungarian electricity market can be characterised as a mature market with an important role for large European companies. In 2012 the total gross electricity generation was 34.41 TWh dominated by the Paks Nuclear Power Plant (NPP) (45,9%) and gas-fired power plants (25.6%). Coal-fired power plants are also an important part of the electricity mix in Hungary (19.84%), while the share of the renewable based power generation was 6.3%.

Hungary has strong electricity interconnections with its neighbours, the capacity allocations are transparent and the auction quantities are mostly predictable. Hungary has been a net importer since the 1950s. In 2012 the net electricity import was 7.97 TWh, supplying 23.15% of the gross electricity consumption that year.[60]

The total installed capacity in 2012 was around 10 GW. 30% of this capacity (including the Paks NPP) is owned by MVM, a state owned company, while over half of it is owned by large European companies.

For the last decade the gross electricity consumption of Hungary has been fluctuating – in line with economic growth – at around 40 TWh per year, in 2012 it was 39.95 TWh.[61]

In Hungary the wholesale price of generated electricity is market based. Electricity can be traded bilaterally or through the electricity exchange. Since 2010 the subsidiary of MAVIR (HUPX) operates the Hungarian electricity exchange where spot and forward products can be traded. The total traded volume in 2012 in the HUPX spot market was approximately 14.96% of the total Hungarian gross electricity consumption.[62] As there is not an intraday-market yet, forecasting errors have to be corrected via OTC trades. In the wholesale market the major player is the state-owned company, MVM. Through ownership and Power Purchase Agreements (PPAs) with large Hungarian power plants it controls about 50% of the total wholesale market. For this reason the Hungarian Energy and Public Utility Regulatory Authority (MEKH)[63] has identified MVM as a company with significant market power and requested that it sells part of its electricity portfolio through transparent auctions.

In the Hungarian retail market there are three vertically integrated incumbent companies, EON, RWE and EDF, whose subsidiaries hold a license for both electricity distribution and trading. There are around 40 active traders that also operate on the retail market, which mainly supply large or medium-sized industrial consumers. Although household consumers

[60] Source: Statistical Data of the Hungarian Power System 2012, MEKH-MAVIR (2013)
[61] Source: Statistical Data of the Hungarian Power System 2012, MEKH-MAVIR (2013)
[62] Source: HUPX (Hungarian Power Exchange)
[63] Hungarian Energy and Public Utility Regulatory (official abbreviation: MEKH) has been the successor of Hungarian Energy Authority since 2013 April.

have the right to switch supplier, in 2012 only 1.91 % of them purchased electricity from the free market.

The Hungarian Transmission System Operator (TSO) (MAVIR) owns the transmission grid and operates as a subsidiary of MVM, ensuring – in accord with the Independent Transmission Operator (ITO) model – the enforcement of the rules for functional unbundling which conform to the relevant EU Directive. There are six Distribution System Operators (DSOs) in Hungary; all of them are controlled by large European energy companies since the late 1990s.

Hungary has implemented the RES Directives (2001/77/EC and 2009/28/EC). According to the National Renewable Energy Action Plan (NREAP) the RES-E indicative target by 2020 is 10.9%. The majority of RES-E production in 2020 will be based on biomass and wind. In 2012 the total installed RES-E capacity was 759.55 MW, in which wind (42%) and solid biomass (41%) play significant roles.[64] Since 2003 RES-E generation has been subsidized through feed-in tariffs (FIT) and obligatory purchase. While a government decree sets the feed-in tariff[65], the MEKH determines the plant-by-plant length of the support period and the supported amount based on the determination of the payback period. According to present regulation feed-in tariffs differ by size, intra-day time period, the year of commissioning (before or after 1st January 2008) and partly by technology.

The National Ministry of Development is preparing a new support scheme and tariff design, called METÁR which should have entered into force in the beginning of 2013 but it has not been introduced yet. This uncertainty blocks new investments.

2. Determining the maximum connectable renewable capacity

Methods to determine maximum connectable renewable capacity

According to The Electricity Law, TSO/DSOs are obliged to connect RES-E plants which fulfil the prescribed technical and financial requirements. However, the development of wind power is restricted systematically in order to prevent grid operation problems. Wind power plants with more than 50 kW installed capacity must be authorized in a tendering procedure developed and implemented by the Energy Office. Similar restriction is not necessary in the case of PV as no large capacities are anticipated in the NREAP and the level of the feed-in tariff related to PV is relatively low which does not support large scale investments.[66]

Currently about 330 MW of wind power is installed, allocated during the first quota allocation process in 2005. Available grid capacity could accommodate a further 410 MW, which was

[64] Source: Hungarian Energy and Public Utility Regulatory Authority, Annual Report on RES-E and feed-in tariff system (2012)
[65] Government Decree 389/2007
[66] Although for residential application the scheme is more favourable. Due to the net metering applied over a yearly period, households save the full electricity bill over the quantity they consume if they cover it through own-generation. This means that this amount is not supported through the less generous FIT level, but through the full household electricity prices.

the basis of the wind tender in 2009 (cancelled in 2010 before finalisation) and this figure could be the basis of future tenders as well. This additional amount was calculated by MAVIR using the following method: all the intermittent generators were considered as one power plant and the amount of maximum capacity was capped so that it can be regulated without additional procurement of reserve capacities even in the case of an extreme utilization pattern. This calculation was carried out in 2008[67] but the results are still valid according to MAVIR.[68]

Since the transmission grid is strong enough to accommodate the planned amount of intermittent capacity to the system, grid models were not used during the calculation and the maximum installed capacities were determined only by the need of reserve capacities. Accordingly, the calculation was carried out for the whole territory of the country, however during the tendering procedure in 2009 MEKH divided the maximum capacity into two blocks according to geographical location and current distribution (280 MW for the North-Western part of the country, being the most suitable part for wind generation, and 130 MW for the other parts).

Present practices of the TSO

The transmission grid in Hungary is well maintained, it is in a fairly good condition thus there is no need for extra investments because of renewable integration at present. The most important challenge of the TSO with regard to the development of intermittent RES-E is the lack of reserve capacity. According to MAVIR additional regulatory reserves are needed over the amount suggested by ENTSO-E in order to be able to balance securely the weather-dependent generation. MAVIR procures about an additional 100 MW in the case of secondary upward reserves and the procurement of tertiary downward reserves (on average 140 MW) can also be explained at least partly by renewable integration. Under current market circumstances power plants offering regulatory reserves continually suffer losses and some of them stop to operate. If this trend continues, the lack of reserve capacities can become more problematic with the increasing share of intermittent generation. These risks could be mitigated if weather-dependent producers were allowed to be regulated, reducing the downward regulatory reserves to be procured by the system operator. According to MAVIR's current Code of Business Conduct a newly established wind power plant must be capable of downward regulation, and the same was also prescribed in the wind tender. However, currently operating wind power plants are neither obliged, nor motivated to take part in system regulation. There are other MAVIR initiatives to mitigate the problems originating from the lack of system reserves. In April 2013 MAVIR joined the e-GCC project of the Czech and Slovakian transmission system operators which aims to take advantage of the possibilities of cross-border exchange of regulation energy. Beyond that MAVIR started

[67] MAVIR study
[68] Source: interview with MAVIR

negotiation with the Slovakian TSO about the possibility to enable Slovakian power plants taking part in the Hungarian tender of secondary reserves to expand supply.

Another problem of system regulation is that renewable producers hardly have any incentive to maintain their schedule. Although they are also responsible for the balancing energy need of the system, more favourable rules are applied to them than to conventional generation in case of deviations from their schedule. RES-E generators are obliged to forecast their production and give a production schedule to the system operator. The schedules can be modified by 10.00 am on the delivery day for the time period after 12.00 on the day in question without any penalty. RES producers have to pay a 5 HUF (1,6 c€) imbalance fee for each kWh that exceeds or falls under a specified threshold. This threshold is +/- 50 % for wind plants, small hydro plants (<5 MW) and PV, +/- 20 % for small biogas power plants (< 5MW) and +/- 5 % for all other installations. So in case of intermittent capacities, a very high deviation range (+/- 50%) is exempted from the penalty payments. Up to the first six months following their connection to the grid, wind and biogas plants (smaller than 5 MW) can also be exempted from their balancing responsibility.[69]

Although there is a possibility of intraday schedule modification, these deviations from the day-ahead forecast must still be balanced by using balancing energy since in the case of RES-E generation there is no connection between production and consumption and no intraday market is in operation where these schedule changes could be counterbalanced.

Role of the regulator in the process

In order to decrease the risks of system security, the regulator should provide incentives for the participation of weather-dependent producers in system regulation. However, according to European Decree 2009/28/EC the maximum utilization of renewable producers should be ensured, which means that they would be regulated when balancing cannot be solved through traditional system reserves.

3. Queue management

General issues

DSOs are obliged to connect RES-E plants which fulfil the necessary technical and financial requirements. Although according to the Electricity Law RES producers should be given priority connection, in practise grid connection applications are rather handled according to the order they were handed in.

In order to prevent uncontrollable uptake, the construction of new wind power plants is restricted: wind power plants with more than 50 kW of installed capacity can only be built and operated on the basis of a tender process (details later). Despite the fact that a grid connection proposal – issued by the concerned DSO - for a specific grid connection point is necessary to take part in the tender, the overall capacity of applications exceeded the tendered

[69] Government Decree 389/2007, MAVIR Commercial Code

capacities. In the case of other RES-E technologies a similar situation – where demand highly exceeds the targeted application level - usually does not arise and queue management processes are not in place. However, in some special situations it is possible that several new power generation projects apply for a connection permit to the same connection point. For example to apply for the KEOP European investment funds, PV projects had to get a connection offer from the DSO, as a result of which several projects asked for a connection permit to a given connection point with more capacities than it was possible to connect. In those cases the DSOs had to make an order, but there is no regulated and uniform way of doing so. The conditions of connection in this kind of situation are the result of a bargaining process between the generator and the system operator, therefore the DSOs have a discretionary role in the process. DSOs do not have the right to turn down projects which fulfil the prescribed criteria, but it could happen that later applications are assigned less favourable grid connection points that require more investments at higher costs.

Application of queue management methods

Wind power quota allocation methods are the only examples of formal queue management methods in Hungary. First a quota allocation process was held in 2005 when 330 MW of wind capacities were allocated. Then in 2009 a tendering process was opened for an additional 410 MW, but finally it was cancelled in July 2010.

In 2005 MEKH called for a wind power quota allocation process. Investors had to spend considerable time and resources to obtain various permits from approx. 40 different authorities. After having submitted the necessary documents in late 2005, the allocation method was still unclear for the investors. In January 2006, bids for 1400 MW capacities were submitted, while 330 MW was available for allocation. This amount was set by MEKH based on MAVIR’s opinion which claimed that the grid could accommodate only a small amount of weather-dependent sources of power. Finally, MEKH decided that the wind capacity rights were to be allocated on a pro-rata basis, so applicants that fulfilled all the conditions received only a fraction of their claimed capacity size. This decision led to a rent-seeking behaviour with capacity rights traded in a secondary market in order to reach the optimal capacity size.

On 30 June 2009, the Minister of Transport, Communication and Energy authorized the MEKH to start a tender for an additional 410 MW of capacity. This time MEKH provided a detailed document about the tendering method and the evaluation of bids by September 2009. This time the evaluation method for the proposals was more objective taking into account criteria such as requested capacity (smaller capacities were supported in order to favour domestic investors), efficiency, quantity of obligated purchase and the length of the RES-E support period. However an explicit price auction was not applied, the necessity of giving an offer concerning obligated purchase quantity and length of support period generated an implicit price competition. Despite all of these preparations, in 2010 the newly appointed Minister for National Development amended the decree regulating the wind tender, including a new point: the tender could be cancelled if more than 10% of the applications were incomplete and/or incorrect. Using this amendment the Ministry forced MEKH to cancel the process in mid-July 2010. According to MEKH and the Ministry, further integration of wind power would increase end user electricity prices which went against the policy of the government to limit the energy expenses of households. In spite of the sound preparations, political interests overwrote the intentions of the regulator, but at this time instead of network constraints, the impact on end user prices was used as the rationale behind the decision.

Role of the TSO/Energy regulator and the Ministry in the process

Both of the above mentioned quota allocation processes are prime examples of regulatory failure. The first round induced rent-seeking behaviour which led to a non-transparent capacity allocation process. In the second case, although the tendering process was more transparent and objective, political interests conflicted with the goal of the regulator. As the role of the regulator would be to establish a stable and attractive legal framework and to provide a transparent and stable environment as regards tender conditions, this political move undermined the whole tendering process. Since 2010 the tendering process has been postponed together with the new RES-E regulation.

Although, according to our information, not a single complaint arrived to the MEKH because of the unfair connection process, it would be worth for the regulator to consider the introduction of a more precise regulation in order to reduce the number of grid connection applications to the realistic ones. Since RES-E producers do not have to pay any fee when submitting the grid connection application or in exchange for the preliminary information supplied by the grid operator, RES-E producers hand in a high number of applications in order to find the best option for grid connection. This situation is problematic, it leads to additional work on the part of the grid operator as they do not know which projects will eventually be realized. Moreover, due to false applications it could happen that the best projects get less favourable connection possibilities. This problem could be mitigated if a charge for grid connection applications was introduced or a reservation fee or advanced payment was be paid by the applicants. The regulator should also consider to specify official deadlines regarding the grid connection process (deadlines currently are set by system operators and can differ from case to case).

4. Connection charge regime

General issues

Grid operators are not allowed to refuse to connect a plant to the grid: neither due to expected capacity shortages, nor in cases where they will incur additional costs because the grid needs to be expanded or reinforced due to the RES-E development. Ministerial Decree No. 76/2011[70] establishes the main conditions of the connection procedure and the setting of connection costs, but the exact grid connection regulations (requested information and documents) vary from DSO to DSO.

Allocation methods

Grid users pay a connection fee to the grid operator once they are connected to the grid. The grid connection tariff consists of the grid connection basic tariff, a construction tariff of the connection line (a charge for the extension of the grid from the connection point to the plant, which can be asked only from users connected to the low-voltage grid) and a grid enforcement tariff (a charge for extension works beyond the connection point) if necessary. These fees are not regulated, the decree requires only the application of the common least cost principle, but the connection's place and the cost division are determined by the agreement between the grid and plant operator. Household-sized plants do not need to ask for permission (they only have a notification obligation) and they have to pay the grid use charge just as if they were simple consumers, in spite of becoming micro-producers of electricity.

There is a mixed form of shallow and deep cost approach in place. In general, plant operators have to pay the grid connection basic tariff and the grid connection line's construction tariff. The cost of grid reinforcement with regard to a certain grid connections must be borne by the grid operator (in line with the shallow cost approach) to a length of up to 50 m of aerial power line and 25 m of underground power line for the low voltage grid and to a length of up to 250 m of aerial power line and 125 m of underground power line for the medium voltage grid. However, if the necessary grid enforcement operations exceed the aforementioned length, the power plant operator is obliged to pay the grid enforcement tariff (in line with the deep cost approach).

Present practice

The realisation of the necessary grid enforcement is the obligation of the system operator, although it can ask for contribution from the power plant developers. They have to agree on connection fees which cannot exceed the cost of the investment needed for the connection. If the grid enforcement enables the connection of more users, then they share the connection cost proportionally. If new power plants connect to the same connection point and use grid developments which were previously financed by a plant which connected earlier, the newly connected plant must pay the corresponding proportion of the previous enforcement cost and the plant connected earlier gets a cost compensation. Although renewable generators do not gain any priority during the connection process, they have the possibility to ask for a reduction of the connection fees. The connection fee can be reduced in the following cases: if

[70] This decree changed several times: previously 58/2005, 11/2006, 117/2007 Ministerial Decrees established the main conditions of the grid connection procedure

at least 70% of the generated electricity comes from renewable sources, the plant operator can get a 30% discount from the connection fee; and if at least 90% of the generated electricity comes from renewable sources, the plant operator can get a 50% discount. Power plants often do not take advantages of these discounts because DSO are more active if full costs are paid, and on the other hand these costs would be recovered during the FIT payment period. E.g. if these costs are higher, the longer the period the developer receives the FIT to cover the full investment costs.

Although grid operators are responsible for the necessary expansions in order to enable connection to the grid, producers have the possibility to carry out those works themself after agreeing on the technical conditions with the grid operator. However, even in this situation the ownership and maintenance responsibility of the connection instruments and the part of the grid over the connection point should be passed over to the system operator and will belong to the public network. Construction of the connection by the developer on its own has the advantage that the cost and time needed for the realization can be under the control of the developer, but on the other side a lot of problems can arise in reaching the agreement and the administrative and settlement process is complicated as well.

Since the connection process and the division of costs associated with grid enforcement are not precisely regulated and the grid operators have a strong bargaining position, power plant owners have an incentive to cooperate with the DSOs in order to find a connection possibility which is mutually favourable for both of them.

Role of Regulator/Ministry in the process

Although the cooperation between plant and grid operators is mostly smooth (we do not have information about complaints submitted to the MEKH regarding this question), if the deployment of renewable generators accelerates, the elaboration of a more detailed regulation of the connection process should be considered.

5. DSO incentives

Regulatory environment driving DSO activities

Electricity system usage charges are regulated by Economic and Transport Ministry (GKM) Regulation 64/2011 and the maximum levels are set by the Energy Office.[71]

To determine system usage charges, a price cap regulation is adopted with a four year long regulatory cycle. For the first year of a regulatory period charges are determined based on the system operators adjusted costs and the quantity data from two years ago (year –2). Between the second and the fourth year of the regulatory cycle the actual value of the charges are

[71] The currently valid maximum levels are set in the MEKH decree about the Electricity system use tariffs for 2013.

modified according to the incentive scheme in place in order to increase the efficiency and improve the services of DSOs, with the following goals included:

- to increase their economic efficiency
- to meet the service quality requirements
- to support the consumers' activities to increase energy efficiency
- to avoid taking unreasonable risks
- to be able to make their economic and business policy decisions with proper foresight

If a DSO can reach an improvement in efficiency in excess of the expectations of the regulator, the additional cost saving remains with the DSO.

Those system users that connect to the distribution network are obliged to pay transmission and system operation charges, a charge for ancillary services and distribution charges which are the following: distribution basic charge (HUF/connection point/year), distribution capacity charge (HUF/kW/year), distribution energy charge (HUF/kWh), distribution reactive power charge (HUF/kWArh) and distribution loss charge (HUF/kWh). These charges are differentiated according to the voltage level of connection. Electricity producers do not have to pay grid use tariffs. Beyond the above charges profile based users have to pay a distribution time schedule balancing fee (HUF/kWh) as well.

Present practices in motivating DSOs to actively participate in distributed generation

As mentioned earlier, according to regulations renewable generators should be given a priority during the grid connection process, but in practise they hardly gain any. Moreover, DSOs face a conflict of interest regarding the connection of RES-E to their grid because of the regulation of connection charges. If RES-E producers opt for the above mentioned reduced connection fee, only 50 or 70 % of the grid investment cost is paid by the RES-E generators, the rest has to be financed by the system operators. Although these additional costs are included in grid use charges, so the grid operators can pass these costs to the end consumers, the compensation will only occur in the next regulatory cycle. Household-sized plants create additional problems for the DSO because their operation decreases the DSO's revenue. Although the loss of sold quantity will also be taken into account when determining grid use charges for the next period, this still implies a significant delay in receiving their revenue. In addition, wind-dependent renewable generators cause uncertainty in service quality which makes it more difficult to meet the quality requirements set for the DSOs as well.

Key findings

1. The penetration of RES-E technologies is slow in Hungary, due to various factors. PV receives a very low level of FIT support compared to other EU countries, while wind projects are constrained by the compulsory tendering process. The biomass use in electricity generation in Hungary was focused up till now on the large scale co-firing option, which was

a rather short term solution to reach EU RES targets, but reduced the uptake of new, efficient biomass capacities.

A positive promotional tool applied in the country is the net metering for households with PV installations, as a consequence of which higher growth rate is expected in the future, also aided by decreasing PV panel prices and the improving attitude of the DSOs toward these installations.

2. As the network is quite strong and stable, the TSO determined wind capacity limits based on the reserve power capacity need, assuming wind capacities as one large intermittent power plant. This assumption is supported by the fact that wind plants are densely located in the North-West of the country. Following this assumption the capacity limit had been determined first at a rather low level, which was more than doubled two years later, even though the calculation methodology was similar. An important factor in determining the capacity limit is the regulability of the plants. As new wind plants can be equipped with this option, the capacity limits could be increased by prescribing the compulsory application of the necessary technology.

3. The 2005 quota allocation process showed that the applied pro-rata allocation is inefficient, leading to the uncontrolled rent-seeking behaviour of RES-E developers to reach an economically efficient size and a more sophisticated tendering process is required to select those investments that are most advantageous from the point of view of economic efficiency.

The wind tender of 2009 worked relatively well (1100 MW application for the 410 MW capacity limit), the regulator included various factors in the evaluation in order to enhance the allocation method: locational signal, regulability, quantity of obligated purchase and the demanded length of the RES-E support period. However, the option to bid for the required FIT level by the applicant was still not used. Ultimately, political will cancelled the tender in the final phase due to concerns on the end user price impacts. Reopening of a new tender is still awaited by investors but the kept postponed.

4. In the connection charging procedure Hungary applies a hybrid approach, where RES promoters can ask for reductions from their payment obligations. In practice RES developers generally cooperated with the DSOs in order to optimise location and cost sharing, and sometimes they paid an extra cost for connections in order to ensure timely connection. In some areas of the connection rules the regulation is incomplete, only provides higher level guidelines, increasing the discretionary role of the DSOs.

VIII. CASE STUDY – TURKEY

1. Brief country description

Turkey's electricity market is characterised by an ongoing transition towards a more competitive operation: the market share of the state-owned power generation company (EÜAŞ) has been steadily decreasing from 74% in 2001 to 45% in 2011 and further to 38% in 2012, while all state-owned DSOs had been privatized by mid-2013. Turkey is keen on establishing better interconnections with its neighbours: the country's accession to the Entso-E means that from 2013 its interconnection with Bulgaria and Greece strengthened, while Turkey also has plans on better interconnections with its eastern and southern neighbours.

By the end of 2012 the total installed capacity was 57 GW: the largest share of this capacity was given by thermal power plants (61%), while hydro power plants constituted 35% of the total capacity. Meanwhile wind power plants were 4% of the total, and the capacity of geothermal plants was below 1%. In the same year the total gross electricity generation was 239.1 TWh, of which thermal power plants generated 174.5 TWh (73%) – a majority of which was provided by natural gas fired power plants while coal also had a substantial share – , hydro power plants generated 57.8 TWh (24%), while the share of wind power was only 3% with 5.9 TWh, and geothermal power plants generated less than 1 TWh of electric power.

Considering Turkey's renewable energy policy, during the past years attention was mainly focused on wind power: following an enormous amount of application for wind power licences at the national energy regulator (EPDK) in 2007, the regulation had to be revised to be able to accommodate a large amount of decentralised wind connections. Thus, for wind and solar energy, a tendering process was created, and for solar power the electricity market law set a 600 MW generation cap for 2013 in the first round of the tenders. The framework for renewable regulation is partly based on the renewable utilization law (YEK,2005), which was amended in 2011; and partly on the electricity market law. Currently, tenders for wind and solar power are held by the TSO (TEİAŞ), while connection permits are issued by either the local DSOs and/or the TSO – RES licences, however, are issued by EPDK.

Turkey's renewables targets are set for 2023 in the Electricity Market Strategy Document which was adopted in 2009 by the country's High Planning Council. The overall goal is to increase the share of RES-E to 30% of total electricity generation. To achieve this, Turkey intends to increase wind power capacity to 20 GW by 2023, while also reaching the full economic potential of hydroelectric power, which is estimated at 40 GW. Moreover, Turkey intends to utilize all of its geothermal potential, currently estimated in the range of 600-1,000 MW. At the same time, Turkey also aims at the widespread utilization of other renewable energy sources, mainly solar and biomass. The driving forces behind Turkey's renewable-friendly policy are:

- a desire to diversify its energy resources to mitigate its dependency on electricity imports as domestic demand is increasing;
- the aim to improve the cost-efficiency of electricity supply for consumers;
- and the objective to increase employment by helping domestic equipment manufacturing.

In Turkey the wholesale price of electricity is market-based: electricity can be traded either under bilateral power trade contracts or within a power pool.

At the moment there are 21 separate regional DSOs operating in Turkey: the current market structure is a result of the privatisation of the state-owned distribution company (TEDAŞ) which started in 2001. TEDAŞ was formerly the owner of 20 out of a total 21 regional DSOs (the only other distribution region has been operated by the partially private KCETAŞ company). Currently the regional companies are all privatized, while distribution assets remain under the ownership of TEDAŞ. At the same time new investors buying DSOs attain the right to operate the network while being obliged to undertake the necessary investments in the distribution grid. The DSOs are price regulated entities as a revenue cap is applied to the distribution system usage fee: the revenue cap is approved by EPDK for each five-year implementation period, while the estimated total distributed energy for each DSO is approved by EPDK annually. The current tariff implementation period of 2011-2015 is characterized by a relatively high capital expenditure budget and lower operational expenditures set for DSOs compared to the previous period: the higher capital expenditures can be explained by the regulator's attention to technological investments like SCADA (supervisory control and data acquisition system), geographical information systems and grid automation systems. In Turkey, service quality is also enhanced through incentives as revenue caps are increased from the baseline for DSOs with better service quality and decreased for DSOs with lower quality: this incentive, however, was postponed until the end of 2013 as distribution companies could not provide service quality data, which they explained by the lack of the necessary infrastructure. Required measurement equipment has to be installed until the end of 2013. Submission of data to the regulator will start by 2014, and target values of quality indicator parameters for each DSOs are planned to be in force in 2015.

2. Determining the maximum renewable capacity

Methods to determine maximum connectable renewable capacity

In Turkey there is no nationwide maximum capacity set for wind connections, but the connectable capacity is determined by TEİAŞ on a substation basis and auctioned every year. However, for solar power a 600 MW cap is applied (which includes both solar PV and solar thermal plants) until December 31, 2013, i.e. the first round for solar capacity tenders. There is also a cap for individual connections for solar power plants, setting the maximum individual connection at 50 MW. The 600 MW limit has been in place since the enforcement of the YEK law – that is since the end of 2011 – and has been determined on a substation basis by TEİAŞ, taking into account the extent of intermittent generation which is manageable with the current infrastructure. The 600 MW limit is subject to increase in the future in line with network and capacity developments.

The maximum capacity was determined by the new RES legislation (YEK). The limit is explained by the excessive amount of wind power applications in the first round of wind capacity tenders, as the regulator intends to preclude a similar upsurge in solar power applications.

For both solar and wind power, there is an ex ante evaluation process which takes into account local characteristics of available energy resources and the local grid. Turkey is also developing more sophisticated wind power forecasting and monitoring which it intends to incorporate to the grid planning and management process. For licencing solar plants there is a mandatory 12-month solar irradiation measurement period, and measurement also continues after commissioning.[72] This measurement, however, is unrelated to the 600 MW cap. For licencing wind plants there are power flow studies carried out: the TSO evaluates the effect of wind variability on power flow and the local grid, and bases the planning of investments in substations and transmission lines on these evaluations. There is also an evaluation of connectable wind capacity, which investigates the impact of wind power plants on the grid's characteristics. For financial talks to start, there is a mandatory 12-month on-site measurement for wind power installations.

Present practices of the TSO

Currently, the Turkish regulator emphasizes that the level of maximum grid-connectable wind and solar power capacities in the future will depend on both network developments and the development of installed capacity. Another measure to facilitate the connection of more wind power to the grid will be better wind forecasting and monitoring. The TSO, TEİAŞ, has not yet procured additional secondary or tertiary reserves as a result of increasing wind power generation, but it states that additional reserves will likely be needed in the near future if wind and solar power usage spread according to the present plans. However, the regulator believes that better forecasting will be able to mitigate the need for additional reserves. At the present, each wind power plant sends their forecasted output for the next 48 hours in an hourly breakdown to TEİAŞ every day at 12 am.

[72] Out of the 12 months of measurement, 6 months have to be „on-site” whereas the remaining 6 months can be obtained from meteorlogical data.

3. Queue management

General issues

The current system of queue management in Turkey for wind and solar power was created as a response to a very large number of wind power applications: on a single day – November 1, 2007 – capacity applications came in at more than 70 GW, well in excess of the 40.8 GW total installed capacity of Turkey at the time. Hence in Turkey the main problem of the large amount of wind power licence applications was that many of these were overlapping – either with several applications for a given substation or with overlapping plant sites. As a response for this excessive amount of applications, the Turkish regulator EPDK delayed applications for both wind and solar, and spent three years on creating a transparent process by which winners among overlapping applications are selected and issues licences for them. The rules and steps of the process are published by TEİAŞ and EPDK.

By January 2012 EPDK issued licences for 7491 MW wind capacity: of this, 1725 MW was operational by early 2012 while the rest of the capacity was under construction. At the same time, due to the large amount of wind applications the EPDK has not yet issued licences for solar power projects: the first round of solar capacity tenders was completed during the second week of June 2013. A total of around 500 applications for about 9 GW were received, and their evaluation is under way. By early 2012 there was 114 MW of geothermal capacity commissioned, while another 155 MW of capacity had licences and were being constructed. The total volume of issued biomass licences amounted to 135 MW. Although a very strong growth is observed in hydropower – in early 2012 there was 29,700 MW worth of issued licences of which 14,295 MW was under construction – these mainly mean large HPPs.

Methods of queue management

Currently, licence applications are open for every renewable category except for wind and solar: however, solar power applications opened only recently, in June 2013. Licences can be granted for a maximum of 49 years: Renewable based power licences are granted by EMRA and technical assessment is provided by the General Directorate of Renewable Energy (YEGM), and for hydro projects by the General Directorate of State Hydraulic Works (DSİ).[73] At the beginning of the application process, TEİAŞ publishes available capacity for every substation for connecting wind or solar power, while the required documents are published on the regulator's website. In case of hydro, project assessment and auction is carried out by DSİ prior to the licence application. After the application process ends, conditions for grid connection are determined by either the relevant DSO or TEİAŞ, and approved by the regulator.

[73] DSİ also signs water usage contract with the licensees.

In case of multiple applications, usage rights are granted through tenders by TEİAŞ for wind and solar power, and DSİ for hydro power projects – the tenders for wind and solar are based on bids per MW capacity since March 2013, called ‘contribution margin’. This contribution margin is paid by the winner to TEIAS in addition to standard connection and system usage fees that all parties are subject to pay. The regulator EPDK’s role about usage rights is to complete all of the legal procedures needed to obtain the usage right of the plant site in case it is not owned by the investor.

In case the assessment is positive, the application is approved, and some obligations may be determined for licencing. Following the successful application an Environmental Impact Assessment (EIA) is carried out by the Ministry of Environment and Urban Planning. The investor has to sign a contract with either TEİAŞ (wind and solar) or DSİ (hydro): at this stage of the process, before final licencing, there are usually obligations for the investor to increase the limit of the initial collateral (which is 10,000 TRY per MW of capacity), amend the status of its company, or increase the capital of the company – these obligations must be fulfilled in 90 days, the only exception being the deadline for a comprehensive EIA (if needed), which is 300 days. If the investor fulfils all obligations, then the project obtains a licence.

4. Connection charge regime

Allocation methods

Turkey employs a shallow connection regime, meaning that fees only cover part of the direct costs of connection. If there is only one application for a certain substation, the regulator allocates the connection right to the sole applicant and pays the standard connection and system usage fees. If there are multiple applications for connection at a substation, the connection right is given out based on a sealed auction where the applicant with the highest bid wins the connection right: the bid is the fee (in USD) per kWh the investor is willing to pay if the licence is obtained. This usage fee reflects the scarcity of the network resource. As there is a limit on its usage, developers pay a fee for using it, thus the higher bid or bids should be accepted, till the resource is fully utilised. This fee is reflecting the RES-E developer’s willingness to pay for the given resource. This information, together with the wind speed measurement data could be used by TEİAŞ later, to estimate the connectable potential more precisely, which might result in increased connectable capacity values. The willingness to pay the usage fee also gives information to the TSO on where it should increase network capacity in the near future.

Present practice

In the Turkish system renewable energy sources have a priority in connections to a certain substation when competing with conventional power plants – however, as we have seen above, due to technical limitations available wind and solar capacity is fixed on a substation basis. At the same time there are a number of measures to support RES penetration: RES investors only need to pay 1% of the regular (one-off) licencing fee; they are exempted from paying the annual licence fee for the first 8 years of their plant's operation; there is an 85% deduction in system usage tariffs for the first 5 years of operation which is applicable for plants commissioned no later than December 31, 2015. This latter reduction is also extendable for a maximum of 5 years.

In general, there is a fixed ("regular") licencing fee at the time of connection which is to be paid by the investor, and also an annual licencing fee, from which RES producers are exempted in the first 8 years of the plant's operation. It is, however, possible to operate a small, household scale plant (currently up to 1 MWe capacity) without either obtaining a licence or registering a company ("exempted generation").

A key element of Turkey's renewable promotion is that all electricity consumers pay for renewables as the RES fee is included in their electricity bills – the Turkish regulator stresses the importance of all consumers in the country supporting green power generation. Renewables are promoted in a number of ways, two of the most important ones being fixed feed-in tariffs and purchase obligations for suppliers, whereas all suppliers must procure renewable power in proportion with their share in total electricity supply.

The present practice of TEİAŞ in determining the maximum connectable capacity and allocating it according to the highest bids received for the usage of the network could be viewed as a cautious approach to explore the network's limits, and at the same time gain more information for future planning and development. In this way Turkey created a unique, and up till now working method to control the speed of a very high uptake of RES-E, while at the same time bringing economic rationale into its network charging.

Key findings

1. Turkey has been characterised by fast RES-E development for the last years due to its proactive policy in the field, aiming to reduce import dependency and supporting the strong growth in electricity demand. Wind capacities are already auctioned and a 600 MW auction is planned for solar systems for this year.
2. Turkey needs substantial grid developments and better forecasting, monitoring tools to support further RES-E connections to its system.

3. Turkey applies a unique queue management system for wind installations, where project promoters bid up their usage charges for connection (paid on each MW of capacity) in case of multiple applications for a given connection point and/or site. It is an effective and transparent auctioning method to handle the queues of applicants. At the same time, by applying this tool, the TSO also receives information on the promoters' willingness to pay, and also on the locations where the grid needs to be reinforced in order to accommodate more RES-E capacities.
4. A further regulatory tool to promote RES-E development is providing a significant reduction from the connection and grid usage fees for RES-E projects for a period of up to 5 years.

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