



TRAINING ON INFRASTRUCTURE INVESTMENTS

TRAINING REPORT: INFRASTRUCTURE INVESTMENTS, NETWORK REMUNERATION, AND TARIFFS

*Empowering Mediterranean regulators for a common
energy future*



Electricity
Working Group
(ELE WG)



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ABSTRACT

This document gives an overview on the topics that were discussed during the training on “Infrastructure Investments, Network Remuneration, and Tariffs” that took place in Milan, Italy on the 18th, 19th, and 20th of October 2022 in the Secretariat’s offices. The training was attended by several international speakers from MEDREG regulators and collaborating entities specialized in their fields and an array of representatives of energy regulators from different countries in the Mediterranean region.

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DISCLAIMER

This publication was produced with financial support from the European Union. The contents are the sole responsibility of MEDREG and do not necessarily reflect the views of the European Union.

ABOUT MEDREG

MEDREG is the Association of Mediterranean Energy Regulators, bringing together 27 regulators from 22 countries, spanning the European Union, the Balkans and the MENA region.

Mediterranean regulators work together to promote greater harmonization of the regional energy markets and legislations, seeking progressive market integration in the Euro-Mediterranean basin. Through constant cooperation and information exchange among members, MEDREG aims at fostering consumers rights, energy efficiency, infrastructure investment and development, based on secure, safe, cost-effective, and environmentally sustainable energy systems. MEDREG acts as a platform providing information exchange and assistance to its members as well as capacity development activities through webinars, training sessions and workshops. The MEDREG Secretariat is located in Milan, Italy.

MEDREG wishes to thank in particular all the experts for their work in preparing the training and for sharing their knowledge.

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EXECUTIVE SUMMARY

Multiple facets are crucial to the advancement of the energy sector and to drive the energy transition. Some of the main factors affecting them are the infrastructure, network remuneration, and tariffs that reflect well the costs of production and the needs of the consumers. To tackle these three pillars, MEDREG organized this training with speakers from different backgrounds that can best fit the highlighted subjects.

Investing in the infrastructure of power and gas systems should consider all the advancements that are happening in the global energy markets. Energy transition is entailing a lot of incorporation of distributed generation through renewable energy as well as demand side management options which lead to a different development of the infrastructure. The power grid should develop into an interactive web which manages power flows in all directions. This is not familiar to the way that the existing infrastructure operates by delivering the power from the production sites to the end consumer in a monodirectional flow of energy. The accelerated technology change, demand side management opportunities, decentralized energy production along with many other innovations will not only help enhancing the energy structure but will present new challenges in terms of load management, congestion, cybersecurity, and other facets.

It is also important to keep an eye on the network requirements such as remuneration calculation methodologies for transmission, transport, storage, and distribution. Incentive regulation can play a major role in developing the network requirements if it was set in a way to enhance the network and push it to follow the state-of-the-art developments. It can be used as an incentive in case the companies will be updating the network further than expected but within the necessities of the grid, or as a penalty if the companies do not respect certain minimum requirements that are requested by the regulators. Additionally, as RES projects are under development worldwide, the requirements to connect them to the grids should be regularly updated to follow any breakthrough in the sector.

Tariffs are an essential component in energy transition as poorly designed tariff schemes will have a big effect on the stakeholders and might seclude a part of them if not well planned. Currently, most of the southern neighborhood of the Mediterranean relies on subsidies for both the electricity and gas sectors. However, while alleviating the subsidies, tariffs should be calculated in a way to be fair and cost-based with all stakeholders and protect the vulnerable consumers.

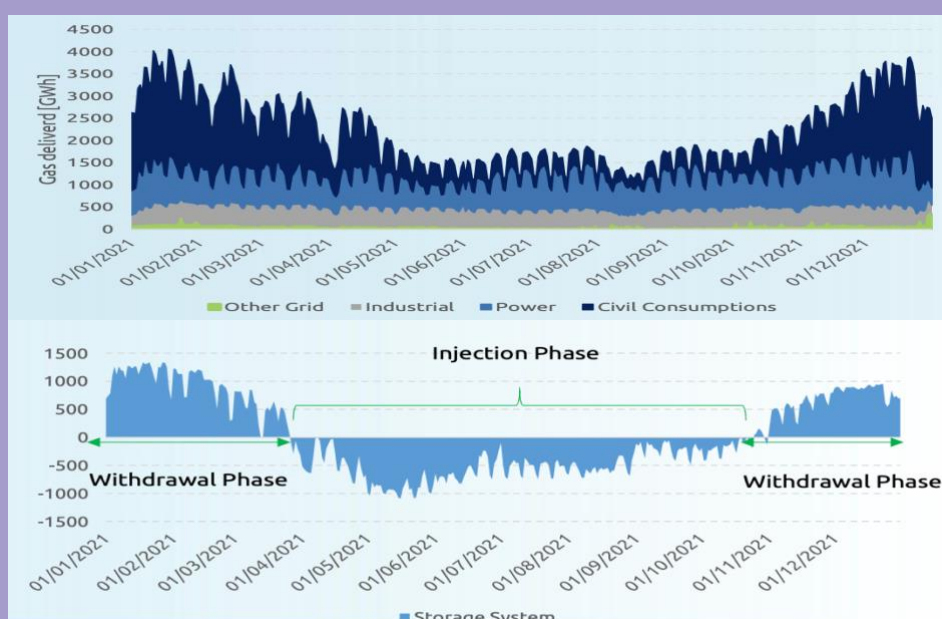
This training will tackle these three main pillars. The first day stresses the importance of infrastructure by discussing transmission and distribution investments and how they should be made to maximize the return of decarbonization. Then, network remuneration will be highlighted by tackling subjects such as the methodologies to calculate remunerations for the electricity and gas transmission, transport, and distribution, as well as the requirements to connect small and large-scale renewable energy projects to the grid. Day three focuses on the tariffs by discussing the alleviation of subsidies and setting cost-reflective tariffs.

1.1. Planning of Gas Transmission and Distribution Investments in the Era of Decarbonization (Nicola Battilana, Head of Asset Planning, Snam)

Snam is Europe's largest natural gas operator with consolidated experience in developing and managing complex projects for the gas infrastructure. Snam has a network of 32,683 kms of pipes, 13 compressor stations, around 200 active networks, 76 bcm of injected natural gas, 8 supervision and control districts, and 48 maintenance centers. Italy has six points of entry for import pipes and three LNG terminals. In 2017, after its reverse flow investments, Snam exported gas to Switzerland for the first time. In 2022, the long-term export facilities towards Austria were maxed out at the Tarvisio point.

The consumption profile is almost steady for the industrial and power sectors throughout the year. The only sector with high variability is the civil sector which increases its consumption during colder periods. This should normally lead to an increase in prices, but the storage system has a key role in mitigating this effect and ensuring security of supply.

Figure 1. Consumption profile for different sectors and the operation of the storage system during 2021



The development of the gas grid is driven by multiple factors that could be enticed by the market such as new entry points interconnected with new supply sources, or a capacity increase of an existing entry point, or new requests for connecting final customers. This development could also be pushed by the TSO due to their demand and supply analysis and new network configurations. The infrastructure is a key driver of energy transition, and it should evolve from its current form of vertical systems to an integrated and circular ecosystem. Policy scenarios envisage a decline in the natural gas demand compensated by the increase in green gas demand.

Biomethane is a renewable gas generated from biomass, manure, depuration sludges, and organic fraction of municipal waste. Biomethane is suitable for all energetic needs, and it does not require switching costs for the end-users and it can be transported in existing infrastructures. It has a potential of supplying 41 bcm/y from the EU-27. Biomethane is an enabler of circular economy and helps enhancing the security of supply. REPowerEU foresees investments around 37 billion Euros to increase the production of biomethane and its use in households, industry, and agriculture.

On another front, hydrogen has multiple benefits mainly being a clean gas that does not emit CO₂ or other pollutants when used, to other facets such as being more cost-effective than electricity in transportation, being convenient for long-time storage, can decarbonize the hard-to-abate sectors such as steel and refinery, and can also be used in sustainable mobility and other fields. REPowerEU has set a target of 10 Mton of hydrogen production by 2030 and 200 million Euros funding to accelerate hydrogen projects. The European backbone for hydrogen is being developed under several targets for 2030 and 2040. Five main supply corridors are considered as important to supply hydrogen to Europe. One of the main challenges for hydrogen is that the hard-to-abate sectors have a flat profile throughout the day, and RES production is unpredictable, so storage will be required on a daily basis, and the sizing of hydrogen/RES production should be adequate to avoid the risk of curtailment.

1.2. The Role of the Mediterranean Region in European Gas Supply Security (Bruno Castellano, Senior Energy Analyst, OME)

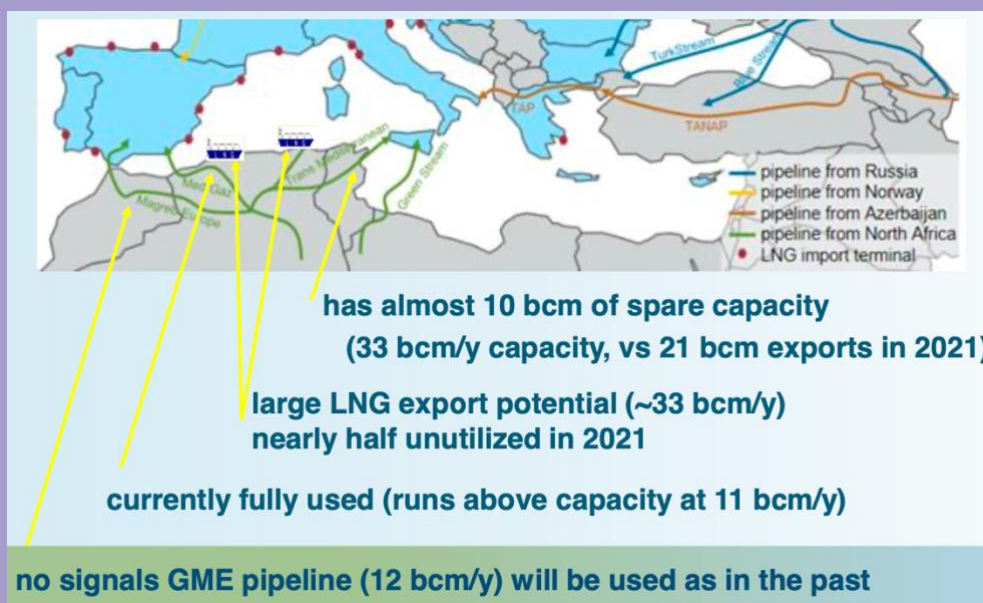
REPowerEU sets a detailed plan to end the EU's dependency on Russian fossil fuel imports. It consists of diversifying the imports to non-Russian suppliers of 50 bcm of LNG and 10 or more bcm of pipeline gas. Additional facets of the plan count on substituting the fuel with renewable and low carbon energy sources, enhancing energy efficiency and related savings, and provide financing plans for them.

Gas production in the EU has been declining since its peak in 1996 from 182 bcm to 51 bcm in 2021, while imports have been increasing leading the import dependence to surpass 80% since 2019 and reach 88% in 2021. The Norwegian gas production is expected to peak in the coming few years and the EU needs to search for alternative sources. The EU receives 2/3 of its gas by pipelines through 4 main corridors from Azerbaijan, North Africa, Norway, and Russia. In 2021, the Russian imports exceed the third of the total imports of the EU.

In the EU, there are 21 large-scale LNG regasification facilities providing a capacity of 170 bcm/year. In the region of the south Mediterranean, the estimated conventional natural gas resources are more than double the region's gas reserves. Since 1980, gas production in the region has increased and surpassed 200 bcm in 2021 with Algeria and Egypt being the biggest producers. From the opposite side, demand in the south has also increased and exceeded 200 bcm. In 2021, Algerian gas exports reached 55 bcm with more than 80% going to Europe.

The figure below, shows the opportunities available for Algeria to increase their gas imports to its customers in Europe based on the available capacities in the existing pipelines. In 2021, production in Algeria reached a record 100 bcm, but the consumption also increased to reach around 45 bcm. The country has significant gas resources, but they require a higher level of activity, infrastructure, and advanced technology. To help reduce the consumption, it is important to reduce gas flaring, replace gas with alternative fuels, and increase the share of renewables in energy production.

Figure 2. Figure describing the available capacities in Algerian pipelines



In Libya, security and political instability lead to a continuous decrease in the exports during the last decade, reaching 3.2 bcm in 2021. In Egypt, LNG exports in 2021 reached 9 bcm with 8 bcm of unutilized LNG capacity. For Israel, several export solutions are under consideration, and if they are accomplished, it can increase further its exports to Europe in the mid to longer term. The south Mediterranean has a huge potential for export that could reach 100 bcm in 2030, compared to less than 60 bcm in 2021.

The trans-Adriatic pipeline (TAP) has a capacity of 10 bcm/year and has transported 8.2 bcm in 2021. Its full capacity should be reached in 2022. Currently, a market test is undergoing to double the pipeline's capacity, but this will require large investments and a time market between 3 and 4 years.

The EU is urgently trying to compensate the lack of the Russian gas and the southern Mediterranean can play an important role. In the short term, the south Mediterranean can provide at least an additional 6 bcm, while in the mid-to-long-term, it could provide up to 40 additional bcm (or 50 with the inclusion of the Southern Gas Corridor). Hence there is an important need to enhance the coordination between the EU and the south Mediterranean region to overcome the existing challenges.

1.3. The Role of Distribution Grids in the Energy Transition: Regulatory Trends (Valeria d'Ettore, Senior Analyst, Enel Grids)

The evolution of the electrical system has a huge impact on distribution grids, and hence on the role of the DSOs. In the old system, most of the generation plants were connected to the transmission grid and the TSO handled the system adequacy. With the increase of large-scale renewables, the problems of RES volatility and congestion emerged, but it still had no-to-small effect on the distribution grids. With the increasing penetration of distributed renewable energy generation such as solar rooftop, the flow became bidirectional and less predictable in the distribution grids and towards the transmission grids. With further electrification of the end consumption through EVs, storage, heat pumps and similar applications, the majority of the energy will be produced, used, and balanced within the distribution grid, highlighting the need for local flexibility services.

Until now, DSOs were responsible for distributing electricity to final consumers, monitoring consumption and distributed generation with smart meters, managing and controlling the network, and planning network investments. Currently, its responsibilities are evolving to include near real-time monitoring and controlling of distributed generation, acting as the orchestrator of the energy system, managing network congestions and voltage regulation, and evaluating the availability of flexibility services.

Several regulatory trends are emerging to support the new role of the DSO under energy transition, remuneration schemes, resilience, grid reliability, customers, and safety and environment. To help DSOs reach their objectives, NRAs should allow them to procure flexibility services under market-based procedures and provide them with incentives. The network development plan should provide transparency on the medium and long-term flexibility services needed. For remuneration schemes, TOTEX is a remuneration mechanism based on total cost recognition tied to predefined spending targets. Other TOTEX related approaches use a total cost approach for benchmarking purposes and defining cost efficiency scores for DSOs. The benefits of TOTEX remuneration is that it focuses on optimizing spending, increasing transparency of investments, and defining of adjustment factors with respect to what is included in development plans while the risks include less flexibility in operational choices, variability in economic environment, and complexity in identifying industry standard costs to evaluate efficiencies.

With all the threats posed by climate change, a resilient grid is an instrumental element of the power sector. It is important to secure a robust infrastructure, a good forecast of extreme events, and fast network reconfiguration to mitigate the effect of severe weather by ensuring the continuity of supply and assets damage prevention. This can be achieved by reinforcing and renewing the grid, increasing the interconnections, using automation, and coordinating with other stakeholders. The DSO's resilience plan should aim to achieve, for each selected intervention, a lower risk index of power outages after the investment.

With all these developments, the grid management is continuously increasing in complexity. Multiple contributors such as decarbonization plans, electrification and urbanization, decentralization of generation, prosumers centricity, the expanding array of digital tools and platforms are leading to this complexity. This

can be alleviated by opting for smart technologies such as advanced metering, grids digitalization, and on-field activities digitalization. In short, innovation and digitalization will lead to a sustainable evolution of the DSOs.

Smart metering can be used to enhance the experience of the customers by providing them with additional data to better understand their consumption and how to lessen their energy bills. This is why smart metering should be well regulated to provide data security for the customers while ensuring the data reaches the relevant stakeholders.

2.1. Requirements for the Connection of Small and Medium-Scale RES Projects to the Grid (Konstantinos Perrakis, Coordinator, RAE)

A general overview of the grid connections shows that energy flows from big scale power production plants that are connected to high-voltage lines and then transformed and transmitted on 110 kV to big industrial plants and medium-size production unit. After this stage, the voltage is transformed to be distributed on medium-voltage lines and then as a last step, transformed to low-voltage 400V where the end-consumers and small production units are connected. Wind projects under 5 MW can be connected to the same connection line, while a project of about 20 MW should have its own connection line but it can be connected along with other connections at the substation. Projects of 100 MW should not have any other connections at the substation where they are connected.

New rules are being established for VRE grid connections. The integration of a significant share of VRE into grids requires a substantial transformation of the existing networks to introduce technologies and procedures to ensure proper grid operation, stability, and control. The three main considerations to take into account for PV-grid interconnections are the safety, power quality, and anti-islanding. The main requirements related to the integration of VRE into grids are:

- 1- Voltage control/reactive power control which is the ability of VRE plants to respond to voltage fluctuations at their point of interconnection.
- 2- Frequency control/active power control which is the ability to provide active power regulation, particularly downwards, in response to over-frequency.
- 3- Fault ride-through which is the ability of the generating units to remain operational during transmission system faults and disturbances.
- 4- Synthetic inertia

Grid codes are technical requirements that must be met by everything connected to the electricity network. It aims at ensuring that the electricity network works in a safe, secure, and economic way. Different stakeholders see them in different lights such as the TSOs who advocate strict requirements for connections, power plant owners who prefer the requirements not be too strict and consider the special characteristics of renewable power generation, and the supply industry who root for predictable and standardized requirements that align between requirements and technology capabilities. However, with the expansion of VRE power, the requirements will get stricter and stricter. The ENTSO-E network code proposes requirements for grid connection applicable to all generators that will help simplify the interpretation of the grid codes and set the frame for national grid codes. The power generating modules are separated into 4 categories based on the voltage level of their connection point and on their maximum capacity. The code contains provisions dealing with frequency stability, voltage stability, Robustness, and system restoration.

According to Directive 2009/28/EC, TSOs have an obligation to connect RES projects except in very specific cases where they must provide justification. Congestion in the internal network is an important problem to examine while developing transmission plans. It can be dealt with by preemptively overbuilding transmission capacity to anticipate the needs, or with centralized planning for RES and booking the transmission capacity. The allocation of transmission capacity can be completed by either opting for a first-come-first-served basis or aiming for a centralized approach by using tenders. Congestion management can be tackled in both long and short-term plans. It can be identified in the connection offer, at the time of connection of the project, and during operation.

When considering the connection modes, two important issues must be examined, the allocation of costs between TSOs and generators new and existing, and the ownership of the connection network. It is also important to notice that there are 2 cases that emerge at connection. The first case is that the users appear at different times. In this case the first user should be reimbursed by the subsequent users based on a methodology of calculation defined by the TSO and approved by the NRA. The second case is that all users appear at the same time, which is basically when the TSO issues connection offers to all prospective users. The problem in this case is that the users must coordinate to complete the network connection and some problems may arise from the fact that some user at the end may not build the plant. In the interconnection point, the connection boundary is the border determining the financial responsibilities between the TSO and the applicant. The connection offer should contain an outline of the connection solution proposed, an outline of the necessary works and reinforcement, the technical and communication requirements, and cost information.

To enhance transparency, the TSO should publish the connection applications and the progress of each application periodically, and the RES capacity that may be connected to the transmission grid. The DSO should also publish the same information related to the distribution network as well as the methodology to calculate the RES capacity.

2.2. Methodologies to Calculate Remunerations for the Gas Transport and Distribution: Focus on Security and Flexibility (Mehmet Kurkcu, Group Head of Foreign Relations, EMRA)

The methodologies for calculating the transmission and distribution tariff are set by board decisions covering tariff-making methodologies, analysis of the DSO investments, OPEX calculations, consumer number and demand forecast along with other parameters. Transmission, distribution, and connection tariffs are regulated by law while for the regulation covers the wholesale tariffs only in its principles. The storage tariff is regulated until enough competition exists as required by law. Supply and trade and LNG storage and gasification are not subject to price regulation, but the discrimination should not exist between the parties. The retail price of gas is formed from the natural gas wholesale price, distribution charges, and taxes. The natural gas wholesale price by itself consists of the commodity price, transmission charges, storage charges, and taxes.

The main principles for calculating the transmission tariffs consist of calculating it by revenue cap method, with the objective of compensating fixed and variable costs and providing a fair rate of return to sustain the incurred investments. The tariffs are composed of capacity and service charges and of dispatch control charges that are defined in the network code. The overall methodology consists of defining the revenue requirement, deducing the annual revenue cap, and setting the transmission charges. To determine the revenue requirement, several elements should be identified such as the return, depreciation, return for line pack, investment compensation, and the OPEX. Elements such as the regulated asset base (RAB) and the weighted average cost of capital (WACC) should be calculated to extract the values of the return and return for line pack. The return for line pack covers the cost of the Line pack that is borne by the TSO. Its unit cost is calculated based on current gas prices on the market, and the amount of line pack for the upcoming tariff period is calculated taking into consideration the average line pack amount of the previous years and the transmission grid expansions. The investment compensation should be added to the revenue requirement of the first year of the subsequent tariff period. OPEX only covers operational costs necessary for transmission services. It includes the cost of gas used internally in the system but does not include financial costs. One percent of the regulated OPEX is awarded as budget for R&D. the conversion from revenue cap to unit charges is defined in the method statement, and in the Turkish case, it is proposed by the TSO and approved by EMRA. According to the existing method statement in turkey, 45% of the revenue cap should be met through the capacity charges while 55% should be met by service charges. Unit charges consist of service charges, capacity charges, and standard service fees.

For distribution tariffs in Turkey, the investment model and main principles consist of the following. In the first eight years of operations, DSOs are bound by the prices they bid in the tenders. After this period, tariffs are determined by EMRA according to the price cap methodology for 5-years periods. Financial costs, exchange risks, losses, and bad debts are not considered in the tariff calculation. The revenue requirement is built from multiple blocks such as the return, depreciation, CAPEX compensation, OPEX excluding the operational revenue, and the working capital expenses. Here the RAB is calculated at the end of the tender period and then for the coming periods based on the investment excluding the total depreciation. Then the CAPEX analysis is performed to reach the average RAB. A unit cost analysis is also performed at the end of which an incentive-based approach is used to remunerate the DSO for cost-efficient measures. The difference between return and depreciation is also calculated to extract the investment compensation. The WACC is calculated in the same manner as for the transmission tariffs. Additionally, the OPEX is analyzed to be added in the distribution tariff. The process includes an efficiency analysis where detected efficiencies should be eliminated in a timeframe of 10 years.

In distribution, demand forecast is based on the consumption levels, where volumes consumed that are less than 10 million Sm³ are forecasted via time series analysis, and consumptions above that value are forecasted by considering consumers' and DSO's consumption prediction and the past consumption.

Finally, the revenue requirements are allocated by the regulator to consumer groups and the distribution charges are calculated for each consumer level. Tariff revisions are done when there is an extension of the distribution zones, when a large-scale consumer enters in an existing distribution zone, when there is a need for additional investments, and when there is a significant deviation from the consumption forecast.

2.3. Methodologies to Calculate Remunerations for the Electricity Transmission and Distribution (Paulo Paulino, Economist, ERSE)

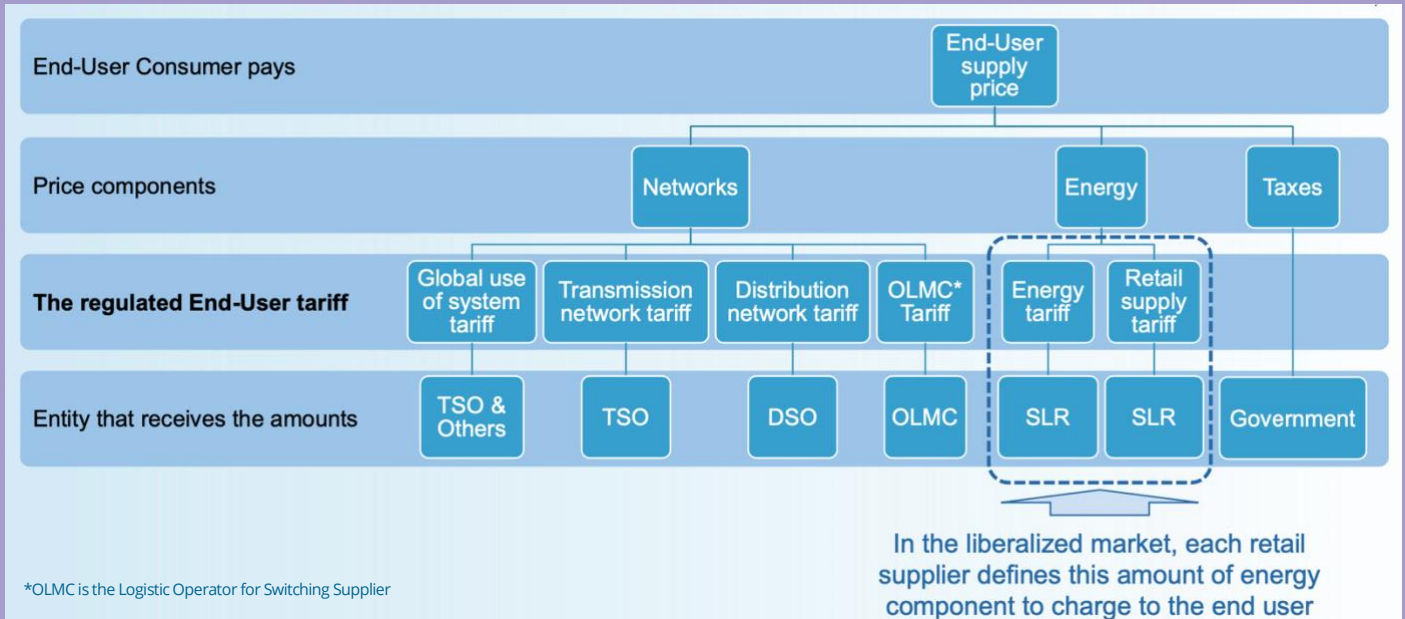
In theory, the maximization of a monopoly's profit happens by choosing the maximum quantity where the marginal revenue is equal to the marginal cost and allocating to it the maximum price that the market is willing to pay to get this commodity. When this happens, the resulting price and quality imply a loss of social efficiency. By applying regulatory methodologies defining the revenues/profit allowed for the regulated activity, economic regulation stimulates a competitive environment. A natural monopoly occurs when a single company can supply a service to an entire market at a lower cost than other firms could. When the total average cost continually declines, a single firm can produce any given amount at the smallest cost, that firm is a Natural Monopoly. When using regulated prices, attention should be given to the fact that no company can operate at loss for a long term. This is one of the main challenges that the regulators are facing. Economic regulation promotes resource allocation and technical efficiency, technological innovation and preparation of the sectors for future challenges. It also ensures the quality of services and their alignment with standards while giving a fair return for the companies.

Revenues are calculated based on the costs of the regulated companies favoring efficient costs, and economic regulation helps define the amount of income allowed to these companies. On the other hand, tariffs are calculated based on the allowed income to the companies, and the methodology must transmit the appropriate economic signals to the consumers. It is essential to secure non-discrimination between users, transparency, cost-based tariffs, and the absence of cross-subsidies. The aim is to provide companies with cost recovery if they are efficient, create incentives for investing in new infrastructure, attract capital, provide users with proper economic signals for efficient use of resources.

Revenues are collected by the application of tariffs that are set to provide each activity with an amount of allowed revenues as per the applicable tariff regulations. In Portugal, for consumers who are still in the regulated market, ERSE defines a transitory end-user tariff applied by the supplier of last resort (SLR). It can be defined as the sum of the energy and supply tariffs and the network access tariff. However, both in the liberalized and the regulated market, all consumers pay the network access tariff and the taxes, the only difference is in the energy and supply tariffs. The figure below details the components of the end-user supply price reaching the entities that receive the relevant amounts.

While developing the methodology for tariff calculation, the definition of each parameter should be transparent and consistent from the accounting perspective to the financial pretax WACC definition. The regulator can approach the calculation of remuneration from multiple angles if it defines the most appropriate methodology. This methodology might depend on the available information, the number of operators, the ownership of the companies, and the maturity of the regulated sector. In the Portuguese case, all the parameters are well defined to secure the transparency of the methodology and detailed information on the calculations of these parameters and the significance of each one can be seen in the presentation given by Mr. Paulino during the training.

Figure 3. Components of end-user supply price



*OLMC is the Logistic Operator for Switching Supplier

3.1. How to Remunerate the Different Components of Tariffs (Konstantin Petrov, Head of Section Policy and Regulation, DNV)

The maximum allowed revenues are determined by arrangements defined by the regulators. These allowed revenues will be distributed by voltage levels and consumer categories. This will lead to a tariff structure that may be different based on the cost allocation of groups and services. Pricing principles diverge into 5 main axes consisting of cost recovery, cost causality, transparency and simplicity, efficient regulation, and non-discrimination. Cost recovery is simply the right of the regulated companies to recover their CAPEX and OPEX costs. Cost causality depends on the location, energy consumption, and voltage level connection which reflect the cost imposed by the end-user to the system. Transparency and simplicity are important so the end-user could easily understand his bill and hence accept it and they are also essential to reduce the administrative burden and risks of potential disputes. Regulators should encourage the regulated companies to operate efficiently and minimize their costs to comply with the regulations. Finally, it is important to have a leveled field for all market players and treat all users equally by applying the same methodology to calculate the charges.

In the electricity network pricing methodology, network services, connection services, network losses, and other services should be considered in the final price. The pricing concept should be based either on marginal pricing or average cost pricing. Several factors should be accounted for during the allocation of costs for the tariff such as the geographical locations, different voltage levels, time dependent pricing, and allocation to network users. Network pricing has 3 main axes that are the transaction base which describes the logic of the network service provision, the network pricing design which focuses on the structure of the tariff and the allocation of costs, and elements such as charges for provision of connection, and network and systems services. The transaction base defines the concept of energy delivery which can either be from point-to-point or as an integrated access model. Network pricing design can be based on average cost or marginal cost. Average cost being the total costs for provision of the regulated service divided by the total demand, and marginal cost being the full economic incurred in supplying a small increase in demand of the relevant service given the demands placed on the system by all users. Marginal cost can be seen under different forms such as short run marginal cost (SRMC), long run marginal cost (LRMC), incremental cost, or long run average incremental cost (LRAIC). Payment liability defines who pays the usage of the transmission and distribution services. In several countries, generators do not pay transmission fees to incentivize investments and to give them an edge in cross-border competition. For the distribution network, all users of the network are benefitting from its services, and thus should pay the distribution charges. Tariff structures can be differentiated following several models, some of which are the time-of-use charges, locational pricing, and differentiation by voltage level. There is no universal best practice form the calculation of transmission tariffs. In Europe, different pricing models were developed depending on the local circumstances, tradition, and the market system.

To set the tariffs and allocate the costs, 4 steps are identified, starting with the setting of the allowed revenue, to the functional allocation, then the allocation to customer groups, and tariff setting. The allowed revenue consists of the OPEX, the depreciation, and the return on assets. For the functional allocation, customers should pay for expenses related only to their voltage level and higher. There are also other factors for functional allocation such as the required capacity, energy dependent costs, and number and type of customers. The allocation to customer groups can be based on several cost blocks such as demand, energy, or customer dependent cost blocks. It can be different based on the demand and number of customers and availability of demand data. The tariff structure is normally chosen to accurately reflect the cost of service with a tariff element and depends largely of the type of cost allocation adopted.

Retail suppliers purchase electricity and distribute it to the consumers. This energy is their largest cost item, but some additional costs will be added to their purchase due to various activities that they perform. Retail margins are set as a sales percentage or as a fixed allowance per customer. Regulatory activities should properly consider the specific characteristics of the supply activities whilst still establishing an adequate margin.

3.2. Reduction of Subsidies in the Design of Electricity Tariffs (Sherif Zoheir, Head of the Central Department of Electricity Market, EgyptERA)

The price of electricity is constructed from multiple components starting with the generation, to the transmission and distribution. Each of these elements have multiple factors affecting them. Generation and distribution are affected by the fuel price, wages, O&M, and WACC, while distribution is affected by the wages, O&M, and WACC. Within these elements, fuel prices are affected by the international price of fuel and the shipping services. Wages, O&M, and WACC in generation and distribution are affected by both demand and energy while in transmission they are only affected by demand. The RAB and the WACC are essential elements in the calculation of prices.

Many attributes constitute the tariff principles, such as consistency, sustainability, stability, transparency, and multiple other factors. Various types of tariffs exist in the market such as the simple tariff, flat rate tariff, block rate tariff, two-part tariff, maximum demand tariff, power factor tariff, and three-part tariff.

The simple rate tariff is the fixed rate per unit of energy consumed. Flat rate tariff is the scheme where different types of consumers are charged at different unit rates by type. The block rate tariff is when a block of energy is sold at a specified rate, but the following blocks are charged at progressively reduced rates. In the two-part tariff, there are 2 components to the total cost known as fixed and running charges. The maximum demand tariff is like the two-part tariff scheme, but the maximum demand of the consumer is calculated by installing a maximum demand meter at his premises and it is mostly applied to bulk consumers. The power factor tariff is used to encourage the optimal operations, and it consists of penalizing consumers that have low power factor loads and incentivize the consumers that have a PF higher than the

reference. Finally, the three-part tariff has three components in the total charges and consist of fixed charges, semifixed charges, and running charges.

Pricing has two main targets. The first is collecting sufficient revenue to cover the companies' allowed costs, and the second is sending the right economic signals to consumers to optimize economic and social use. The pricing steps should begin with calculating the cost of the generation, transmission, and distribution services, determine the structure of the tariff, and distribute the calculated cost to the assigned structure while considering giving some preferences to some activities and protecting vulnerable consumers.

In Egypt, the subsidy system is set in a way that encourages consumerism. So the more you consume, the more you are subsidized leading to the poorest receiving 10% of the total fuel subsidy benefits, while the wealthiest receive 45% of these benefits. While the cost of electricity in Egypt has been stable since 2014, the average selling price has been gradually increasing, and it has surpassed the cost for the first time in the years 2018-2019 leading to a total recovery of costs of 107%.

Along with the pricing mechanism, a communication strategy is being developed to communicate information and awareness to consumers through several ad campaigns and press releases.

3.3. Market Access for Demand-Response Measures (Andrea Galliani, Deputy Director of the Wholesale Markets and Environmental Sustainability Department, and Andrea Rosazza, Officer, AREG)

Italy has witnessed a fast increase in random energy sources such as wind and solar, and in distributed generation. This has led to the reduction of the programmable traditional power plants by decreasing the traditional sources capable of delivering ancillary services, reducing the system inertia, and changing the network congestion. Since 2014, energy produced by renewable sources have exceeded 100,000 GWh/year. However, when the residual load is studied, it is noticeable that there is a considerable amount of energy that could be produced during the day is being wasted, while at night some of the consumption cannot be completely sustained with RE resources.

Ancillary services are services provided by producers or consumers to the TSO and DSO to control electrical parameters. The term ancillary means auxiliary but indispensable to the main service. These services ensure an adequate level of quality of the service such as continuous delivery and voltage and frequency regulation. Some of these services are the increase or decrease of production, reducing the offtake including load disconnection, and voltage control through controllable production plants, step-up transformers, and dedicated installations. If the offer is accepted on the market, the beneficiary is obliged to execute the commands received by the TSO or DSO. These services are valuable as they entail increased costs that may occur in their absence due to the need to reserve an upward and downward bandwidth, sub-optimal operational points, and the need for measurement, command, and control devices.

In their capacities, NRAs should work on removing undue barriers for ancillary services market, build a framework where ancillary services are attractive for both producers and consumers, and aim for technological neutrality. There is always a need for pilot projects to know how to maximize the contribution of RE distributed generation and to identify new ancillary services.

Participants in the ancillary services market are balance service providers (BSPs) and they give their services through production or consumption units that are not already enabled. Some of the BSP's resources used in some pilot projects are water heaters, solar panels with storage, standalone storage, biomethane cogeneration, run-of-the-river hydroelectric power plant, and EV recharging stations. Although distributed resources are good for the development of the grid, but they are difficult to manage. Some of these difficulties lie in the aggregation which is needed in case of small-scale distributed resources and in the expertise needed to make offer on the energy market, but both of these difficulties can be managed by BSP when they are acting as aggregators. Other problems emerge in the enabling of the system which for example needs necessary equipment to send data and receive commands, and the management and certification of these equipment along with their observability by the TSO, DSO, and BSP and many other difficulties arising from the integration of small-scale distributed generation. It is important in general to keep an approach that is technologically neutral and remove unnecessary entry barriers stemming from previous modes of operation.

Most UVAMs (Enabled Mixed Virtual Units) are made of at least one unit capable of modulating consumptions, programmable production units, and production units that are classified as non-programmable but still have flexibility margins. They can deliver services related to congestion resolution and frequency services (frequency services can only be done on the TSO network). For the future procurement, the TSO procures in advance and through auctions the availability of resources. These resources are obliged to put the offer on the balancing market at a capped price. The remuneration of the future procurement happens through a fixed fee resulting from the auction in which the lowest bidder wins pay-as-bid type and variable fee from the market. Spot procurement is the direct participation of the BSP to the balancing market. In this case, the remuneration is a variable fee from the market. In Italy, in 2022, there are 212 UVAMs, 60 less than 2021 due to the failure of performance test. The units included in the UVAM are 1473 (down from 2327 in 2021). The UVAM projects span over several sectors such as storage, consumption, hydro, solar, thermal, and renewable thermal projects and they are distributed on all Italian territories but are mostly concentrated in northern Italy. There are currently 31 BSPs and the overall modulation capability of UVAMs is 1164 MW upwards and 166 MW downwards. Their modulation capability range are from 1-48 MW upwards and 2-28 MW downwards. Most of the UVAM units are small distributed solar plants. The number of production and consumption units are balanced at almost 700 each. The aggregation of UVAM projects is allowed within predefined areas depending on the ancillary services delivered. It is important that they evolve consistently with the network model adopted by the TSO and DSO



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