BLACK SEA REGULATORY INITIATIVE

WHOLESALE MARKET GUIDELINES FOR BLACK SEA ELECTRICITY MARKET INTEGRATION

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EXECUTIVE SUMMARY

The Black Sea Regulatory Initiative (BSRI) is a collaborative effort of the United States Agency for International Development (USAID) and the National Association of Regulatory Utility Commissioners (NARUC) to provide technical assistance and support to Black Sea national energy regulators to make important incremental steps towards energy sector reform.

The Wholesale Market Guidelines introduce a vision for the future of wholesale market development in BSRI project countries through the promotion of cross-border trade and the associated liberalization of internal national markets. The Guidelines identify the best practices for wholesale market development that are based on European Union (EU) electricity market reforms and the experience of countries that have begun implementing these reforms. The Guidelines also identify the pragmatic key steps in advancing wholesale market development based on these best practices.

The Guidelines were developed by expert consultants in conjunction with U.S. regulatory experts and Black Sea regulators. The Black Sea regulatory agencies include the Public Services Regulatory Commission of the Republic of Armenia (PSRC); State Agency for Alternative and Renewable and Energy Sources (AREA) and Tariff Council of the Republic of Azerbaijan; Georgian National Energy and Water Regulatory Commission (GNERC); National Agency for Energy Regulation of Moldova (ANRE); and National Energy and Utilities Regulatory Commission of Ukraine (NEURC).

The Guidelines provide a technical discussion of pertinent issues related to competitive wholesale market development and propose practical next steps for Black Sea regulators to take in two key areas—1) cross-border trade and 2) balancing and ancillary services.

Below is a summary of the Guidelines' recommended next steps for Black Sea regulators:

Cross-Border Access Recommendations

1. **Coordinated Cross-Border Capacity Calculation and Publication (see section 2.2.2)**
   - Establish bilaterally coordinated cross-border capacity values (e.g., Net Transfer Capacity) and determine the level of coordination by working with the Black Sea Regional Transmission System Planning Project (BSTP).[1]
2. **Open Access Transmission (see section 2.2.1)**
   - Oblige TSOs to create data transparency pages to eliminate information asymmetries. The Guidelines provide an Appendix that summarizes key data to be published.
   - Establish non-discriminatory and transparent tariffs for access to national transmission networks, and, where not yet done, establish unbundled transmission tariffs.

[1] https://www.usea.org/program/black-sea-regional-transmission-system-planning-project-bstp

3. **Congestion Management and Capacity Allocation (see section 2.2.2)**

    - In cases of congestion, the allocation of cross-border capacities should be addressed with non-discriminatory solutions – market-based solutions can be introduced at a later point in time to provide more efficient signals to market participants and TSOs.

4. **TSO compensation for hosting cross-border flows (see section 2.2.1)**

    - Work to ensure that TSOs are compensated for potential costs incurred as a result of hosting cross-border flows of electricity on their networks.

5. **Harmonization of Operational Rules (see section 2.2.2)**

    - Harmonize safety, operational, and planning standards used by national TSOs.

Balancing and Ancillary Services Recommendations

1. **Harmonizing Definitions (see section 2.3.3)**

    - Harmonize the definitions of the products to be used so that eventually they may be traded on a standardized basis. The Guidelines propose that Black Sea countries immediately adopt standardized definitions used in the European Network of Transmission System Operators for Electricity (ENTSO-E) Network Codes (defined herein) to be the basis of this effort.

2. **Pricing Mechanisms in Transition (see section 2.3.4)**

    - Develop cost-based rates for ancillary services and balancing and establish criteria to determine when the market is ready for market-based procurement. The Guidelines offer specific examples of cost-based pricing of ancillary services procurement that Black Sea regulators can use to develop their own methodologies.

3. **Market Monitoring Framework (see section 2.3.5)**

    - In advance of market-based procurement, set up the necessary framework to monitor such markets, including monitoring offers of balancing and ancillary service markets and monitoring aspects of cross-border transmission capacity markets.

4. **Market Coupling (see section 2.3.2)**

    - Establish multi-stakeholder working groups to determine cross-border transmission capacity and to harmonize scheduling protocols. In addition, regulators should initiate and oversee the development of merit-order cost for all domestic resources in preparation for eventual market coupling initiatives.

5. **Integration of Renewables Resources (see section 2.4)**

    - Regulators can begin to identify framework objectives for the integration of renewable resources. The Guidelines identify a number of best practices and principles to guide regulators on developing such a framework.

Establish Governance

To establish some of the key first steps, coordination among major stakeholders (ministries, regulators, TSOs, large consumers, and others) should occur within some governance structure. This will allow engagement in a focused and dedicated activity on a sustained basis to advance the regional objectives. The Guidelines propose that BSRI participants agree to certain common positions associated with key next steps. At later junctures, the BSRI participants should consider more formal written understandings or joint statements addressing common structures and rules for wholesale market reform.

ACKNOWLEDGEMENTS

USAID, NARUC, and the authors of this report would like to thank all the project participants representing energy regulatory commissions from Armenia, Azerbaijan, Georgia, Moldova, and Ukraine for contributing their time and expertise to the development of this document.

Many expert volunteer regulators from the United States, European Union member states, and neighboring countries also attended project workshops that supported the drafting and review of the Guidelines. We thank them for their generous support and commitment to this important initiative.

These expert volunteers include Mr. Hisham Choueiki of the Public Utilities Commission of Ohio, Mr. David Boyd of the Midcontinent Independent System Operator (MISO), Ms. Angela Monroe of the Maine Public Utilities Commission, and regulatory expert volunteers from Turkey's Energy Market Regulatory Authority (EMRA), Serbia's Energy Agency of the Republic of Serbia (AERS), Bosnia and Herzegovina's State Electricity Regulatory Commission (SERC), Romania's National Agency for Energy Regulation (ANRE), and the Romanian Transmission System Operator Transelectrica.

1. INTRODUCTION

1.1. BACKGROUND AND PURPOSE

Since 2010, the United States Agency for International Development (USAID) and the National Association of Regulatory Utility Commissioners (NARUC) have collaborated on the Black Sea Regulatory Initiative (BSRI) to support Black Sea national energy regulators in their efforts to transition their countries towards more competitive, secure, environmentally sustainable, and regionally integrated energy systems. Building upon the previous work of the BSRI, the 2016 project aimed to establish closer trading relationships among the participant countries and to make progress toward the development of regional wholesale markets.

The regulatory bodies that participated in this project are:

The Public Regulatory Commission of the Republic of Armenia (PSRC)

The State Agency for Alternative and Renewable Energy Sources (AREA)

The Tariff Council of the Republic of Azerbaijan

Georgian National Energy and Water Regulatory Commission (GNERC)

National Agency for Energy Regulation (ANRE)

Ukraine's National Energy and Utilities Regulatory Commission (NEURC)

There were three main components to the 2016 project. First, the BSRI participant countries met at workshops designed to facilitate discussions focused on key issues that the countries are facing as they move toward wholesale electricity market reform. Workshops were held in February, June, and November 2016. The first two workshops provided the basis for the second main feature of the project: the Wholesale Market Guidelines. The Wholesale Market Guidelines, as discussed in more detail below, identify best practices and next steps for advancing cross-border trade and balancing and ancillary services markets for the BSRI participant countries. In turn, the Wholesale Market Guidelines provided a basis for the third main feature of the project: the in-country technical assistance and development of country-specific implementation plans or "road maps." The in-country technical assistance portion of the project was designed to provide regulators with close technical support on wholesale market issues and challenges that were most pressing to each specific country. From this work, the BSRI project advisors developed individual country "road maps" outlining specific next steps for regulators to take on a specific rule, regulation, or implementation challenge.

The project workshops, Wholesale Market Guidelines, and in-country assistance have helped illuminate the path forward for the participating BSRI regulators. The path forward focuses on integrating the individual participant countries into a regional market by harmonizing rules, agreements, and operating procedures to facilitate cross-border trading and, subsequently, introducing market-based structures within national wholesale markets and between interconnected neighbors. This will facilitate regional integration and, ultimately, integration within the wider EU market.

This approach to market reform is consistent with the practices of the EU energy market reforms intended to create the EU Internal Energy Market (IEM). Indeed, EU IEM market reforms are comprised of two principal components— (1) regional integration through cross-border trade and (2) national-level wholesale market liberalization. As such, this project was shaped by a similar two-pronged approach that addressed both cross-border trade and wholesale market liberalization. Advancing cross-border trading alone can allow the countries to benefit from the gains of trading, even in the absence of internal market reform. Furthermore, cross-border trade is also critical for the development of national wholesale markets because of the need to develop broader diversity of supply and liquidity within individual countries.

With the approach outlined above, the 2016 BSRI project aimed to provide a vehicle of collaboration for participating regulators to jointly create practical solutions to market reform challenges and move their laws and regulations toward the EU reform model. Indeed, coordination among *National Regulatory Authorities* (NRAs) to achieve the elements of the EU IEM reforms, like the coordination through the BSRI, is encouraged.

1.2. THE WHOLESALE ELECTRICITY MARKET GUIDELINES

The Wholesale Market Guidelines introduce a vision for the future of wholesale market development in BSRI project countries through the promotion of cross-border trade and the liberalization of internal national markets. Identifying the best practices for wholesale market development based on EU electricity market reforms and the experience of countries implementing these reforms, the Guidelines lay out the pragmatic steps necessary for Black Sea regulators to make incremental improvements toward more competitive wholesale electricity sectors.

Issues addressed in these Guidelines are informed by the experience of international energy consultants and technical experts, including peer-to-peer sharing between NARUC members and project country national regulators. Subsequent sections contain the technical discussion of key wholesale market issues and follow the two main elements of EU reform – cross-border trade and internal market liberalization. In each of these two sections, we discuss the principles and practices that comprise the EU IEM and then provide recommendations for incremental steps to achieve these principles and practices.

2. TECHNICAL DISCUSSION OF WHOLESALE MARKET ISSUES

2.1. THE EU ELECTRICITY MARKET REFORMS

The technical discussions within this document are intended to identify the best practices for liberalized wholesale electricity markets and to outline recommend next steps for Black Sea regulators to take in line with these best practices.

The best practices are rooted in the EU market reform process, a process that began in 1996 with the goal of creating a competitive internal electricity market in Europe to provide all consumers with the choice of buying electricity from the supplier of their choice. Promulgated in 2009,[2] the "Third Energy Package" or simply the "Third Package" made a number of changes to the directives and regulations governing the EU electricity and natural gas markets to improve their functioning and to resolve structural problems. It also created a new entity called the Agency for the Cooperation of Energy Regulators (ACER) to provide oversight of the EU energy markets and to promote harmonization of national regulations.

One of the principal changes made by the Third Package was the requirement to separate transmission and distribution from generation and supply — i.e., unbundling. The Third Package also requires NRAs to be independent—not only from private influence, but also from government interference—and increases regulators' powers to protect consumers, monitor competition in the electricity market, and fix or approve tariffs or tariff methodologies for regulated services. While a transparent authorization procedure is mandated to encourage new entrants in the generation sector, the directive allows for the use of tendering procedures, not only to ensure security of supply, but also to promote the use of new technologies and electricity from renewable energy resources (RES). The Third Package also directed the newly created ACER to develop common EU level *Network Codes* to ensure non-discriminatory access and promote cross-border trade, among other aims. As explained in more detail herein, the Network Codes are a series of rules drafted by the European Network of Transmission System Operators for Electricity (ENTSO-E) with guidance by ACER to codify the reforms in the EU directives on energy aimed at providing harmonized rules for cross-border exchanges of electricity and internal market reforms.

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[2] The legislative acts of the Third Energy Package are:

Directive 2009/72/EC concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (the Electricity Directive)

Directive 2009/73/EC concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC

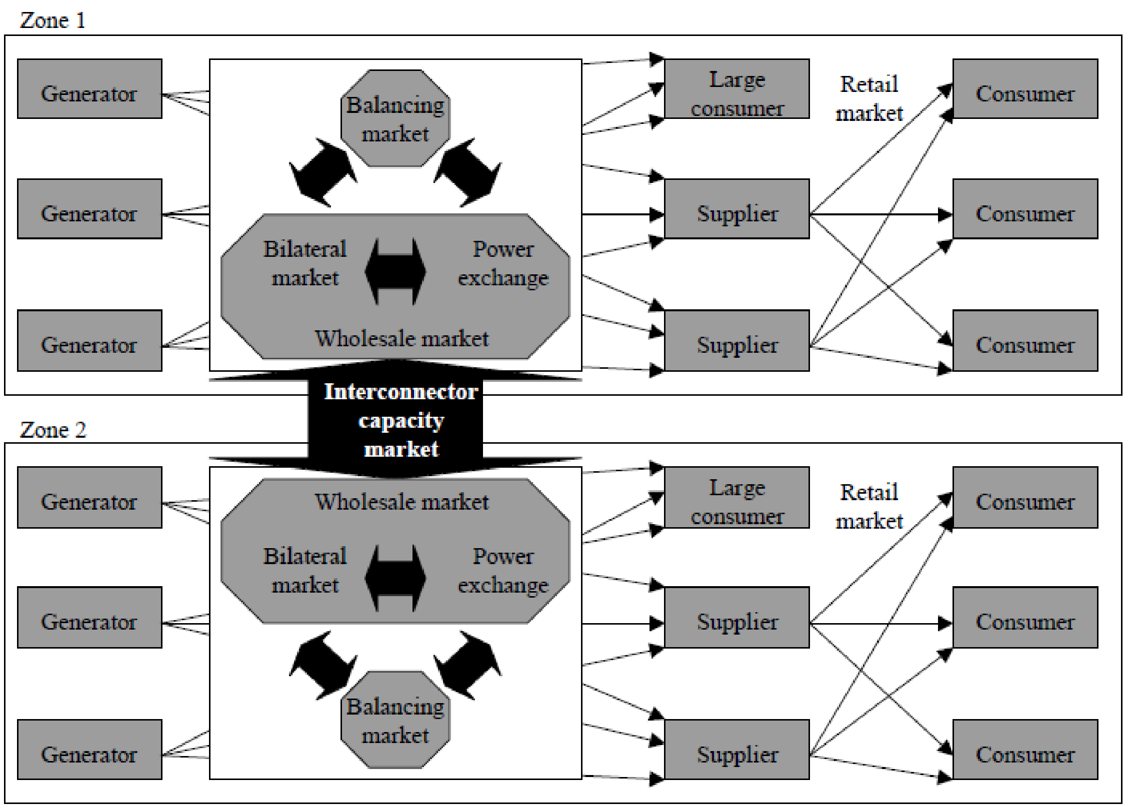
Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 (Regulation No. 714)

Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005

Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators

The EU vision of energy market liberalization is illustrated in Figure 1 below. The figure shows how each country is to establish its own wholesale market, which must then be technically and commercially integrated through interconnections with each neighboring country.

Figure 1: EU Market Vision



Source: Meeus, L and R. Belmans, "Development of the Internal Electricity Market in Europe," *The Electricity Journal,* July 2005.

To achieve this vision, the Third Energy Package requires both integration via cross-border open access and the liberalization of each country's market. Specifically, these goals are to be achieved as follows:

Elements of Open-Access Transmission and Regional Integration:

- Harmonization of national grid codes with regard to cross-border capacity allocation, congestion management, and ancillary services, consistent with EU Network Codes;
- Cooperation of national regulatory authorities in regional matters; and
- Harmonization of market rules to enable regional market integration, consistent with the EU Network Codes.

Elements of Liberalization:

- Unbundling of transmission and distribution system operators (TSOs and DSOs);
- Regulated open-access to the transmission grid;
- Specific regulatory powers for national regulatory authorities and associated independence;

- Retail choice option for all customers; and
- Market-based mechanisms for wholesale trading.

Each of these elements requires certain actions by national legislatures as well as by NRAs. To an important degree, the two areas of EU market reforms are chronological – i.e., cross-border trade and regional integration are prerequisites to national market reforms. In other words, facilitating cross-border trade is an important first reform initiative that subsequently supports opening the internal national markets for more effective competition.

As a result, it is important to examine first the best practices for establishing cross-border trade that will help reshape and intensify trading and that can be modified at later stages to meet EU standards. Indeed, BSRI regulators expressed a desire to be more active in cross-border trading for accessing more economic sources of power, for selling surplus power, and for providing transit services for countries seeking mutually beneficial trades.

The second area of technical discussion is wholesale market mechanisms, structure, and practices. This area involves a wide range of issues associated with designing competitive markets, especially reforming the ancillary services and balancing markets, and includes the role of regulators in approving market rules and monitoring the market.

The Network Codes

The EU Third Energy Package of reforms required ACER to develop "Framework Guidelines," which, in turn, provide the basis for the technical codes drafted by ENTSO-E, known as the Network Codes (also known synonymously as the "Grid Codes"). The Network Codes are an extensive collection of rules and practices that are central to EU electricity market reforms. They are aimed at harmonizing a wide array of practices, rules, and technical standards.[3] Many of the best practices for wholesale market reform are rooted in the Framework Guidelines and Network Codes.

The Network Codes are organized in a chronological sequencing. In particular, the Network Code on Balancing, which specifies the various market-based requirements for balancing and ancillary services trading, is the fifth and final Network Code to be introduced. Indeed, ACER has stated that the Network Code on balancing is the "final building block"[4] to support the EU IEM. One of the earliest codes adopted by ACER was the Network Code on Capacity Allocation & Congestion Management,[5] which entered into force in August 2015 and established the common usage of cross-border interconnectors and day-ahead market coupling (which established rules for day-ahead cross-border scheduling).

The Network Codes ensure harmonized rules on how and under what conditions participants have access to the grid, especially third-party access, and regulate who may use the network to transport electricity across borders and under which conditions. These rules address aspects of network security

[3] There are 12 specific areas that are to be addressed in the network codes listed in Article 8(6) of Regulation (EC) No 714/2009: (i) network security and reliability, including technical transmission reserve capacity for operational network security, (ii) network connection, (iii) third-party access, (iv) data exchange and settlement, (v) interoperability, (vi) operational procedures in an emergency, (vii) capacity-allocation and congestion-management, (viii) trading with regard to technical and operational provision of network access services and system balancing, (ix) transparency, (x) balancing, including network-related reserve power, (xi) harmonized transmission tariff structures including locational signals and inter-transmission system operator compensation, and (xii) energy efficiency regarding electricity networks.

[4] http://www.acer.europa.eu/en/electricity/FG_and_network_codes/Pages/Balancing.aspx

[5] https://www.entsoe.eu/major-projects/network-code-development/updates-milestones/Pages/default.aspx

(ensuring the network works correctly at all times) and interconnections, as well as access to the grid by persons other than the owners of the infrastructure.

In approaching the task assigned to it in the Third Energy Package, ACER is working with ENTSO-E to develop network codes in a number of areas, including:

Network Code: Capacity Allocation and Congestion Management.

In this area, ENTSO-E is developing two network codes: (1) Capacity Allocation and Congestion Management for the day-ahead and intraday timeframe; and (2) Forward Capacity Allocation for the long-term timeframe. These codes are to provide the legal framework and requirements for TSOs and market operators to facilitate integration of electricity markets among participant countries.

The key issues addressed by these two codes include:

- Calculation of cross-border transmission capacity to maximize trading opportunities, subject to security constraints. The process to establish cross-border capacities should be efficient, transparent, and highly coordinated.
- Efficient allocation of congested cross-border capacity using a market-based auction method and, where market-based prices exist, the capacity should be allocated using wholesale prices (market coupling).
- The cross-zonal capacity allocated in the forward timeframe should be financially firm, whereas cross-zonal capacity allocated in the day-ahead and intraday timeframe should be physically firm.

Network Codes: Grid Connection.

ENTSO-E is developing three network codes related to grid connection: (1) Network Code for Requirements for Grid Connection Applicable to all Generators; (2) Network Code on Demand Connection; and (3) Network Code on HVDC Connections and DC Connected Power Park Modules.

The objective of these codes is to develop a harmonized open-access transmission regime that will support a more efficient and secure system operation and result in non-discriminatory usages of the system (i.e., no preference for transmission owners). The codes are envisioned to include the following elements:

- Minimum standards and requirements for connection;
- Derogations;
- Adaptation of existing arrangements to the network code(s);
- Compliance testing, compliance monitoring, and enforcement;
- Promotion of (real-time and other) exchange of information between parties and improved coordination.

The technical content of these codes will provide regulators with guidance on the best practices to ensure efficient and non-discriminatory access to the grid for all qualifying generators.

System Operation Guideline.

The System Operation Guideline is the combination of four separately-developed Network Codes: 1) Network Code on Operational Security; (2) Network Code on Operational Planning and Scheduling; (3) Network Code on Load-frequency Control and Reserves; and (4) Network Code on Emergency and

Restoration. The objective of these codes is to harmonize operation of the system, including security, control, and quality in terms of fixed technical standards, principles and procedures, and the synchronous operation of interconnected power systems. Importantly, the Load Frequency Control and Reserves sections of these Network Codes contain the technical definitions of ancillary services that provide the basis for harmonization of these products across interconnected systems. Harmonizing these definitions is a key step discussed below in advancing wholesale market development.

Network Codes: Balancing.

The final area where ACER and ENTSO-E are developing Network Codes is for balancing. This Network Code provides a focus on the requirement of competition for providing balancing and ancillary services in the internal market. This is addressed in subsection 1 below.

2.2. BEST PRACTICES FOR DEVELOPING CROSS-BORDER TRADE

The most critical aspect of the Black Sea Market Integration is establishing procedures for cross-border trade. While cross-border trade is a key element of the EU internal energy market because it integrates otherwise separate national wholesale markets, it also has great virtue even before internal national wholesale markets are fully developed. Indeed, a very basic motivation for cross-border trade is to take advantage of different prices, diverse resources, and non-coincident demand in neighboring systems. For example, traders can take advantage of the differences in the hydro inflow regimes across the region, divergence in weather conditions, non-coincidence of load patterns, non-coincidence of off-peak holidays, or staggering of demand due to different time zones.

Furthermore, a cross-border regime may also better accommodate bigger and more efficient generators that would not otherwise be profitable. It likewise diversifies the supply available to a given market and increases the opportunities for generators and other suppliers to sell their surpluses. In addition to the potential cost-savings through market optimization, cross-border trade, properly implemented, can also increase security of supply by allowing sharing of reserves. Moreover, it should be noted that in the absence of cross-border market integration, introducing wholesale market reform carries the risk of creating small, isolated markets with increased probability of market power. This is an important issue in the Black Sea region because of the relatively small size of some of the electricity systems.

Cross-border trade already occurs in the region, but on a limited basis. More vigorous cross-border trading will require reformed rules, including the development of mechanisms that support cross-border transmission service as well as scheduling of cross-border transactions on an efficient basis. Even in the absence of fully developed internal wholesale market mechanisms, and even if some countries are more advanced than others in developing such mechanisms, incremental advances in cross-border trading can improve efficiency and are not contingent on internal market development. However, the goal of internal market development will progress as institutions are developed to support more vibrant trade, so long as the incremental advances in cross-border trading are consistent with the future development of competitive wholesale markets.

This subsection discusses the importance of an independent TSO and the critical role of an independent regulatory agency in establishing oversight of the TSO. Separating the TSO from the operation of wholesale generation suppliers is a critical step in preventing vertical market power.[6] In addition, the regulator should have regulatory authority over all key aspects of the TSO's operations and planning. The following subsection establishes the NRA's key responsibilities.

2.2.1. Unbundling, Open Access, and Transparency

As introduced above, one of the fundamental aspects of the EU Internal Energy Market is an unbundled TSO that is regulated by the national regulator to ensure third-party access and transparency. As the Directive EC 72/2009 states:

> Any system for unbundling should be effective in removing any conflict of interests between producers, suppliers, and transmission system operators to create incentives for the necessary investments and guarantee the access of new market entrants.

2.2.1.1. Unbundling

Directive EC 72/2009 identifies three models for unbundling:

(i) ownership unbundling of the transmission and distribution systems from the entity that owns generation and conducts the supply function;

(ii) the independent transmission operator (ITO) under which the transmission operator remains part of a vertically integrated undertaking, but is subject to numerous rules regarding separation of financial, physical and human resources to ensure its independence; and

(iii) the independent system operator (ISO), under which the transmission system assets are spun off to a separate company within the holding company structure; the separate company separately owns and operates the grid.

All three models were intended to ensure non-discriminatory access to transmission by competitors of a vertically integrated undertaking and to ensure adequate infrastructure investments. The regulators' authority to regulate wholesale market activity must include the ability to ensure the TSO's compliance with these independence requirements.

2.2.1.2. Open-Access Transmission

Open access transmission means the ability of resources to gain access to the transmission network to serve load or to transit the system in a non-discriminatory fashion. In principle, open access is simple and can be attained according to the following main principles.

- TSOs allow market participants to use their networks under regulated third party access.
- Non-discrimination means network usage charges should be applied without regard to the countries of destination and origin.
- TSOs should be allowed to charge market participants for using their networks. Transmission charges applied by TSOs should be transparent, cost reflective, and non-discriminatory.

6 Vertical market power means using the control of a critical input (in this case transmission) to control the price of a related function (in this case generation).

- Ultimately, there should not be specific network usage charges in place on individual transactions for declared transits of electricity.

2.2.1.3. Transparency

Transparency is an important component of successful market integration. Under the EU reform, key market data is required to be made public by the TSO. Without listing the individual items required by the EU reform, there are several general categories: (1) system operating conditions (load, generation, imports, and exports); (2) cross-border capacity forecast and actual usage; (3) system investments and planning processes; and balancing (costs, suppliers, and method of choosing supplier if not market-based).

The publication of relevant data is necessary to create a level playing field for market participants by eliminating information asymmetries. TSOs should put in place coordination and information exchange mechanisms to ensure the security of the networks in the context of congestion management. The safety, operational and planning standards used by transmission system operators should be made public. The information published should include a general scheme for the calculation of the total transfer capacity and the transmission reliability margin based upon the electrical and physical features of the network, such as the description of the Network Model in subsection 2.2.2. For other types of information and guidelines on the frequency of publication, see Appendix I on Transparency for a list of the EU transparency requirements for TSOs.

2.2.1.4. Guidelines on Next Steps for Unbundling, Open Access, and Transparency

The following steps are not aimed at fully achieving the wide variety of best practices as addressed in the EU reforms (and developed, for example, in the Network Codes). Instead, these are some specific steps that will begin the process of regulators and TSOs working with each other and among neighboring countries to begin achieving the EU IEM vision.

- TSO should be unbundled from the generation and supply sector in accordance with one of the options for unbundling;[7]
- The publication of relevant data is necessary to create a level playing field for market participants by eliminating asymmetries in information. To the extent possible the relevant data should be consistent with the EU reform packages, as detailed in the Appendix I on Transparency.
- TSOs should put in place coordination and information exchange mechanisms to ensure the security of the networks in the context of congestion management -- this step is best taken in the context of a meeting among regulators and TSOs;
- Regulators and TSOs should agree on a framework for open access among neighbouring countries -- this step is best taken in the context of a meeting among regulators and TSOs.

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7 For a discussion of unbundling options, see, e.g., http://www.ceer.eu/portal/page/portal/EER_HOME/EER_INTERNATIONAL/EU-US%20Roundtable/10supthsup%20EU-US%20Roundtable/10th%20EU-US_Session%20V_Groebel%20-%20unbundling.pdf

2.2.2. Capacity Allocation and Congestion Management

2.2.2.1. Capacity Allocation

Estimating cross-border transmission capacity is a key first step in coordinating cross border trade. Cross-border transmission capacity is the amount of capacity that is available on interconnectors between countries.

The capacity assessment is the process of estimating the cross-border transmission capacity between two control areas. The main part of the capacity assessment is a simulated network model used to estimate cross-border transmission capacity by using assumed network conditions that accurately reflect transmission elements, load, generation, and exchanges between TSOs. These are the "base case" assumptions and the network simulation using these assumptions is called the base case Network Model.[8]

The base case Network Model determines the "base case flows" on each transmission element. This estimate of base case flows is used in determining how much transmission capacity is available to the market, (known as Net Transfer Capacity or "NTC"). This estimate is critical because NTC depends on how much additional flow can be accommodated over the network.

A) NTC

NTC on an interconnection is defined as:

$$NTC = TTC - TRM$$

where TTC is Total Transfer Capacity and TRM is Transmission Reliability Margin.

Hence, the capacity assessment really examines two key elements, TTC and TRM.

B) TTC

The TTC is defined as:

$$TTC = \Delta E + BCE$$

where ΔE represents the extra amount of power over the base case computer simulation that can be exchanged safely in all hours of the period being examined (usually monthly) from one TSO to another TSO. This is modeled under "N-1 criteria," which means the worst single transmission outage is assumed to be prevailing at the time.[9]

BCE represents anticipated exchanges of power during the evaluated period. It affects TTC in two ways. First, it is an additive component of TTC, and consequently, changes to BCE can have a direct effect on TTC. If the BCE value on an interconnection is not accurate (i.e., it does not reflect anticipated exchanges), then TTC (and, consequently, NTC) may be too big or too small.

[8] ENTSO-E, "Procedures for Cross-Border Transmission Capacity Assessments," October 2001, page 6.

[9] See, ENTSO, Op Cit. page 8.

It is important to note that the BCE component of the TTC equation does not mean that part of the TTC is reserved for BCE transactions. Transactions identified in the BCE must secure NTC through the processes used by all market participants. BCE values are reflected in the Network Model to help ensure an accurate estimation of operating conditions.

In assessing NTC, the Network Model simulates expected network conditions using "base case" assumptions and forecasts, which include generation output, load, and the physical arrangement of the network projected for the time period studied. Inaccurate NTC values can occur because a critical purpose of the Network Model is to identify incremental capacity that is available above the base case conditions. The Network Model measures this incremental capacity by simulating the maximum exchange between two neighboring TSOs. As explained above, this simulated exchange is referred to as "ΔE."

ΔE is a simulated exchange in the network model. This is simulated by TSOs exchanging generation between control areas. Cross-border exchanges are gradually increased by increasing generation output in the first TSO and decreasing it in the neighboring TSO. This will cause simulated power flow from the first TSO to its neighbor. Most of this will flow over the direct interconnection, but some may "loop" around through other systems creating a phenomenon known as "loop flow".

The equation above shows ΔE has a direct impact on NTC. Therefore, if the Network Model provides an inaccurate ΔE value, then NTC will be inaccurate.

ΔE is the largest exchange possible between TSOs subject to (N-1) security constraints.[10] Therefore, for a given ΔE, there should be an associated security constraint. In other words, ΔE would be larger, but a security constraint had been reached in the modeling process.

C) TRM

According to ENTSO-E, TRM should be (at most) the sum of:

$U_E + Ur$

Where, U_E is the cross-border capacity set aside for emergency exchanges. These values should be known in advance and reported on each interconnection; the value U_E is specific to an interconnection.

Ur is $k^* \sigma$

Where σ is the standard deviation of regulation deviation (ACE). This is based on historical imbalance values; $k = 3$, (3 standard deviations typically will encompass more than 95 percent of all observations in a randomly disturbed process).

Ur is what must remain on the interconnections to allow the system to use the interconnections to recover from a temporary imbalance. The value would be distributed across all interconnections in proportion to their relative impedances.

Figure 2 is an illustration of the Capacity Assessment.

10 Op. cit., pp. 7-8.

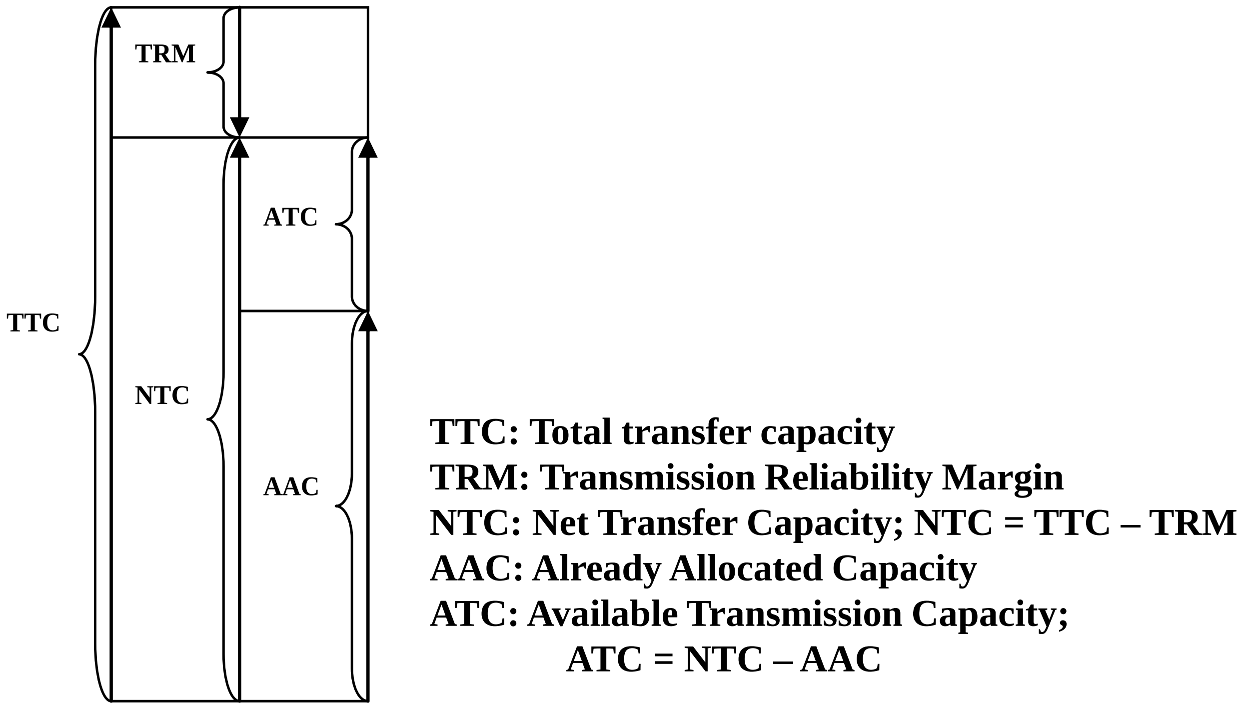


Figure 2: The Capacity Assessment

An agreement on the methodology of capacity calculation and publication is a precondition to launching coordinated cross-border capacity allocation systems in the Black Sea region. Regulators and TSOs are key players in initiating such agreements.

2.2.2.2. Security of Supply

Presently, cross-border interconnections can be weak and may be restricted for large transfers. Attempts to transfer power from one system to the next can create internal congestion and possible instability which must be well-understood before attempting such trades.[11] Ancillary services, discussed below, can provide solutions to key engineering problems, but it is likely that countries will need to dedicate resources to modeling the interconnected systems to understand the limitations from an engineering perspective and assist with policy decisions. There was some engineering work conducted under the BSRI auspices concerning the interconnection between Georgia and Turkey, which could inform future studies as well.

This is an area where cooperation with TSOs can be beneficial. TSOs have critical technical data and studies on the system supply situation that can be conveyed to regulators to aid in decision-making. For example, the Black Sea Regional Transmission System Planning Project work has developed planning models that can be adjusted to assess various future regulatory scenarios. Regulators would likely benefit from working together with the BSTP on planning studies both for security of supply as well as cross-border capacity studies.

[11] Georgia's attempt to trade with Armenia and another neighboring country in 2012-2013 resulted in a blackout of Georgia's system due to frequency and voltage instability in the neighboring country.

2.2.2.3. Congestion Management

An increased utilization level of existing cross-border transmission capacities could benefit investors, generators, and electricity consumers in the Black Sea region. However, an increased level of utilization might lead to (commercial) *congestion*, when the demand for cross-border transmission capacity exceeds available physical capacity at a given border and time period.

In case of congestion, there are several possible methods to allocate physical transmission rights, including cross-border capacities, to market participants (first come, first served; pro rata; NTC-based or flow-based, bilateral or multilateral, explicit or implicit auctions). In Europe, the target model for electricity market integration and congestion management is flow-based price coupling. Until this aim is reached, the interim NTC-based market coupling launched in several EU Member States is likely the best short-term solution in the Black Sea region. The NTC-based market coupling is discussed in more detail below, in subsection 2.3.2., where the issue of day-ahead market coupling is discussed. That section discusses the allocation of cross-border capacity based on offers and bids for power trades between two countries.

The following are some basic requirements for cross-border congestion management.

- In cases of network congestion, the allocation of cross-border capacities should be addressed with a non-discriminatory solution (like day-ahead market coupling). Until market-based coupling is achieved, transparent explicit auctions of NTC are a reasonable solution.
- Except in cases of 'force-majeure', market participants who have been allocated capacity shall be compensated for any curtailment by the TSOs.
- The maximum capacity of the interconnections and/or the transmission networks affecting cross-border flows should be made available to market participants, complying with safety standards of secure network operation. However, a proper treatment of historic (sometimes long-term) contracts, as well as obligations included in inter-governmental agreements should be established in the process of determining available capacity.
- Market participants shall inform the requisite TSOs a reasonable time ahead of the relevant operational period whether they intend to use the allocated capacity. Any allocated capacity that will not be used shall be reattributed to the market in an open, transparent, and non-discriminatory manner.
- Market participants should be allowed to trade formerly allocated capacity rights on a secondary market.
- TSOs should, as far as technically possible, net the capacity requirements of any power flows in the opposite direction over the congested interconnection line to use a line to its maximum capacity.
- The (harmonized) congestion management scheme should be largely revenue neutral from the point of view of TSOs.
- While not immediately relevant, regulators must work to ensure that TSOs are compensated for potential costs incurred as a result of hosting cross-border flows of electricity on their networks.

2.2.2.4. Guidelines on Next Steps for Cross-Border Capacity

Calculating cross-border transmission capacity is a critical first step in wholesale market development. In this regard, there has been important work ongoing among TSOs under the Black Sea Transmission Planning project. The project has produced a common grid model that could be used to facilitate coordinated cross-border transmission capacity calculations. Coordinating future work with TSOs on this common grid model could form the basis of an agreement to jointly determine cross-border capacity. This would provide the basis for a "pilot" program to coordinate bilateral NTC calculations and allocations. The following would be the key principles:

- Establish bilaterally coordinated cross-border capacity values (e.g., NTC);
- Oblige TSOs to create data transparency page - in accordance with 714/2009 requirements - with friendly publication format (see e.g. http://mavir.hu/web/mavir-en/transparency). Start with yearly and monthly auctions;
- Preferably one of the TSOs administers the allocation process for available cross-border capacity, typically a monthly auction of available cross-border capacity;
  - Auction results and prices are published as soon as practicable by the TSOs;
  - When demanded capacity is below available transfer capacity (ATC), the cost of congestion (and thus cross-border capacity use) is zero;
  - An agreement of sharing auction revenues is needed, with a starting point to have the TSO share the auction revenue 50/50.
- Maximum capacity of the interconnections should be made available to market participants;
  - Capacities already under contract should be included in AAC and made transparent.
- Apply use-it-or-lose-it / use-it-or-sell-it that requires participants who have already secured a transmission reservation to either release the capacity back to the TSO if it is not scheduled or to sell it to another party. This makes sure there is no withholding of capacity;
- Allow secondary market for capacity, but TSOs should be informed about the actual use of allocated capacities;
- TSOs should net the capacity requirements of any power flows in the opposite direction;
- Revenue neutrality of the congestion management scheme is preferable.

Next, once reliable NTC values are established and workable in the region, an advanced process would incorporate day-ahead market coupling as discussed in subsection 2.3.2.

Finally, once the day-ahead coupling is achieved, participants should work on intra-day coupling that could also bring significant benefits, such as more flexibility to market actors, more efficient utilization of capacities, more efficient integration of renewable generation, decreased balancing costs, etc.

2.2.2.4.1. Allocation of Costs for Transmission Expansion and Upgrades

Interconnections between two countries, when they exist, can be weak (unable to transmit at high volume) and unstable (may cause internal overload or voltage problems). As a result, in a system where trade is expected to increase, there may be profitable investments that could strengthen cross-border transfer capability and provide mutual benefits.

The EU employs a separate system for Projects of Common Interest (PCIs). PCIs are infrastructure projects aimed at helping EU Member States to physically integrate their energy markets, thereby enabling them to diversify their energy sources and integrate relatively isolated systems. These projects are a subset of projects of Pan-European Significance, a classification of transmission projects identified by the EU in ENTSO-E's Ten Year Network Development Plan. The primary objective of defining a PCI is to accelerate the deployment of capital. This is done by accelerating permitting and planning by requiring only a single national authority to issue permits. By streamlining environmental assessment processes, increasing public participation via consultations, and increasing visibility to investors, a PCI lowers administrative costs. ACER has also proposed ways to allocate the cost of a project by measuring the relative benefit to the two (or more) countries. This approach to sharing investment costs to increase cross-border transmission capacity stands as a feasible model for BSRI participants. However, to attract the necessary investment, existing cross-border trading practices need to be in place.

2.2.2.4.2. Merchant Investment in Transmission

The typical investment in new cross-border transmission facilities will be through the TSO at regulated rates for facilities identified in planning studies pursuant to the ENTSO-E planning process. However, the EU foresees the possibility of private investments under certain conditions for so-called "merchant" transmission facilities. Private parties seeking to invest in merchant facilities must seek exemptions from the standard regulated planning and approval processes. This includes exemptions from regulated third-party access, restrictions on the use of congestion revenues, and ownership unbundling. The request for exemption is ultimately considered by the European Commission (EC). Table 1 summarizes of the exemption process.

Table 1: Summary of Exemption Process for Merchant Transmission Lines

1. Submit Request. Applicant submits a "request for exemption to the NRAs
2. National Decision(s). Since the establishment of ACER, the NRAs must inform ACER of their decision within six months. If the NRAs do not reach a decision, ACER may decide on their behalf.
3. EC Review. Within two months after being notified … of a national-decision, the EC will either approve the exemption or request that the NRAs modify or withdraw their decision. (This initial two-month period is subject to extension where the EC requests additional information or by consent of the relevant parties)

Source : Cuomo, Michael and Jean-Michel Glachant, *EU Electricity Interconnector Policy: Shedding Some Light on the European Commission's Approach to Exemptions, Policy Brief, (June 2012).*

The Electricity Directive, in both the second and third packages, certainly foresees merchant investments. The process, however, requires multiple regulatory approvals. The main considerations in having an exemption are set out in Article 17 of Regulation (EC) No 714/2009:

New direct current interconnectors may, upon request, be exempted, for a limited period of time, from the provisions of Article 16(6) of this Regulation and Articles 9, 32 and Article 37(6) and (10) of Directive 2009/72/EC under the following conditions:

(a) the investment must enhance competition in electricity supply;

(b) the level of risk attached to the investment is such that the investment would not take place unless an exemption is granted;

(c) the interconnector must be owned by a natural or legal person which is separate at least in terms of its legal form from the system operators in whose systems that interconnector will be built;

(d) charges are levied on users of that interconnector;

(e) since the partial market opening, referred to in Article 19 of Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity, no part of the capital or operating costs of the interconnector has been recovered from any component of charges made for the use of transmission or distribution systems linked by the interconnector; and

(f) the exemption must not be to the detriment of competition or the effective functioning of the internal market in electricity, or the efficient functioning of the regulated system to which the interconnector is linked.

2.3. BEST PRACTICES FOR WHOLESALE ELECTRICITY MARKET DEVELOPMENT

As discussed above, cross-border trade is a logical and extremely important step in wholesale market development. The EU IEM relies on cross-border trade to integrate geographic areas into a larger integrated market so that internal, national markets can have increased liquidity and supply diversity. This section examines the key best practices for wholesale market development and practical next steps for countries in the region to advance toward these best practices. Like the proposed next steps for cross-border trade, these proposed next steps are not intended to advance completely to the EU IEM best practices, but are interim steps that can begin the process.

This section is divided into three subsections, addressing: (1) Regulatory Authority over Wholesale Market Development; (2) Day-Ahead Market Coupling and Real-Time Balancing (including Ancillary Services); and (3) Market Monitoring. In each subsection, we include descriptions of the associated next steps in developing these best practices.

2.3.1. Regulatory Authority over Wholesale Market Development

A key component of the EU reform process is the creation of an independent regulator. The reforms require that each member state designate a single NRA that is independent from the government and any private entities. Article 37 of the Electricity Directive enumerates the duties and powers given to the NRA. The lettering of individual paragraphs within section 1 of Article 37 of the Electricity Directive is retained in the quoted passages:

"(a) Approving transmission tariffs or their methodologies;

> (b) Ensuring compliance of transmission … system operators and, where relevant, system owners, as well as of any electricity undertakings, with their obligations under this Directive and other relevant Community legislation, including as regards cross-border issues;
>
> (c) Cooperating in regard to cross-border issues with the regulatory authority or authorities of the Member States concerned and with the Agency;
>
> (g) Monitoring investment plans of the transmission system operators;
>
> (h) Monitoring compliance with and reviewing the past performance of network security and reliability rules;
>
> (i) Monitoring the level of transparency, including of wholesale prices, and ensuring compliance of electricity undertakings with transparency obligations;
>
> (j) Monitoring the level and effectiveness of market opening and competition at wholesale and retail levels, including on electricity exchanges, … any distortion or restriction of competition, including providing any relevant information, and bringing any relevant cases to the relevant competition authorities;
>
> (q) Monitoring the implementation of rules relating to the roles and responsibilities of transmission system operators, distribution system operators, suppliers and customers and other market parties pursuant to Regulation (EC) No 714/2009;
>
> (r) Monitoring investment in generation capacities in relation to security of supply;"[12]

Each of these items should be included in internal legislation and rules establishing the rights and responsibilities of the NRA to achieve compliance with Third Package requirements.

Guidelines on Next Steps for Establishing Regulatory Authority

A key step for regulators is to formally recognize their own authority in the areas listed above as necessary for achieving best practices in accordance with EU IEM. Most countries have the proper authority in at least some of these areas, and others have authority in many of these areas. However, NRAs should formally recognize the need for authority in all of these areas.

As listed above, the areas where national regulators should have authority is very clearly delineated in the Third Package of reforms. Where this authority exists, it may not be in a single item of legislation but may be in two or more items of primary or secondary legislation, regulatory rules, or other administrative rules. An inventory of such authority and its source would help to identify the priorities for new initiatives.

2.3.2. Day-Ahead Market Coupling

The EU IEM envisions wholesale electricity market reforms that would introduce competition in both the day-ahead time frame as well as in the real-time operating period. In the day-ahead time frame,

[12] Electricity Directive, Article 37.

generators schedule power delivery for the next day.[13] Market coupling means the coordination of day-ahead schedules between one or more TSOs to schedule the most efficient combination of resources. It is a scheduling concept, as opposed to the technical operating aspects of balancing (discussed below).

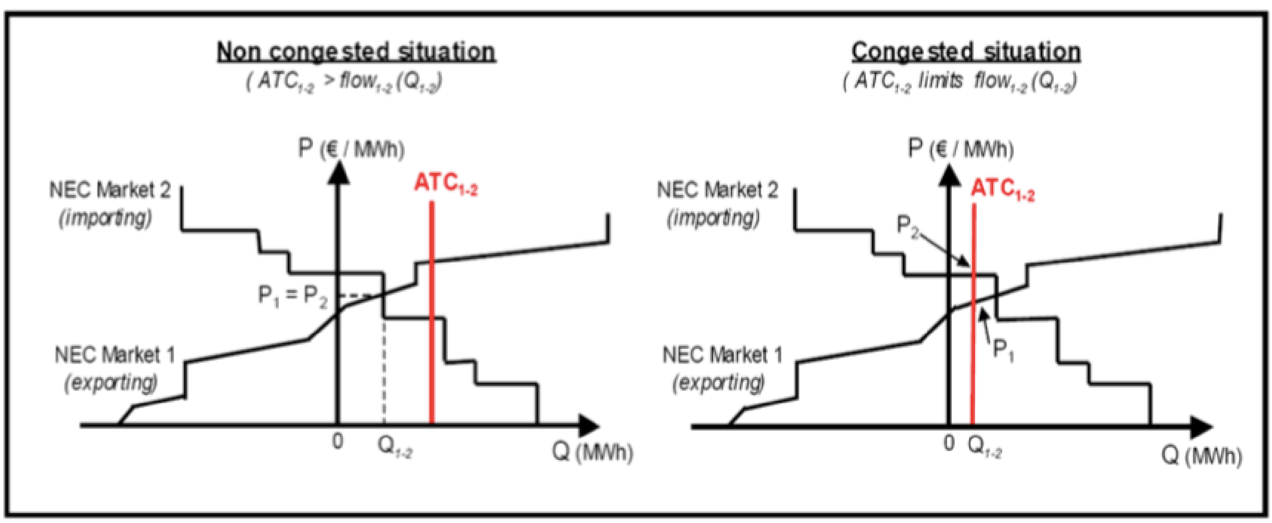
A necessary condition for market coupling is the availability of cross-border transmission capacity, or ATC. As discussed in the cross-border trade section, ATC is the capacity estimated by a TSO that is available across borders. When ATC is available, TSOs can allocate the ATC to the most efficient combination of generators in the market coupling process. Essentially, the TSOs determine which suppliers should gain access to the ATC based on the power supply offers and the cost-savings associated with supplying power across borders rather than scheduling a domestic source.

The following figure was presented at the June 2016 workshop by Mr. Ibrahim Erten from the Turkish regulatory agency, EMRA. It shows the day-ahead coupling process and how ATC is allocated based on an export curve for a "Market 1" and an import curve for "Market 2". An export curve is upward sloping because as price increases, suppliers are willing to export more. An import curve is downward sloping because as prices fall, more imports are demanded. The optimal level of interchange (cross-border flow) is determined at the point where price curves cross

The clearing mechanism is simple, in principle: it permits the exchange of power (MW) to take place, creating the greatest cost savings. Costs are reduced when the importing country replaces its resources with cheaper supply from the exporting country. The algorithm to accomplish this identifies the power blocks in the importing country with the highest cost and replaces them with the power blocks from the exporting country with the lowest costs. The algorithm continues "trading" between the two merit-order stacks until the costs are the same between the stacks (left-hand side of Figure 3) or until the ATC is used up (the right-hand side in Figure 3). The cross-border flows are indicated by $Q_{1\text{-}2}$.

These calculations are accomplished using market coupling software. At the June 2016 workshop, the Romanian regulators indicated that they use a software package called Euphemia, for example.

Figure 3: Illustration of Market Coupling



[13] There is also a similar "intra-day" scheduling process that occurs within the operating day, but prior to real-time. In the discussion on this topic, our reference to day-ahead markets and scheduling also included any intra-day markets or scheduling.

Source: Presentation of Mr. Ibrahim Erten at the June 2016 BSRI Workshop, citing Marek Adamec, Michaela Indrakova, and Pavel Pavlatka, "Market Coupling and Price Coordination between Power Exchanges," (Working Paper).

As explained more below, market coupling is an easier problem to solve than coordination of balancing and ancillary services and should take priority in the regulators' reform efforts.

2.3.2.1. Guidelines on Next Steps for Developing Day-Ahead Market Coupling

2.3.2.1.1. Define ATC

As discussed in subsection 2.2.2., a pre-condition to efficient and effective cross-border trade is that each counterparty knows the amount of cross-border capacity available to participants. A reliable and mutually acceptable ATC value is essential for allocating the cross-border capacity through market coupling.

2.3.2.1.2. Define scheduling

Market coupling seeks to schedule the most efficient mix of resources among two or more interconnected countries. To begin this process, scheduling must be coordinated in two main ways -- it must be for the same time intervals (e.g., hourly, 15-minutes, etc.), and it must have the same gate closures (e.g., day ahead, 4-hours before, etc.). A key first step would be to identify a common approach for scheduling. A reasonable start would be day-ahead schedules for each of the 24 hourly intervals of the next day.

2.3.2.1.3. Define Merit Order Basis

The EU IEM vision for market coupling expects schedule blocks to be priced based on market competition. However, until a workable market is in place, the blocks should be based on short-run marginal costs, as described more in 2.3.4.

2.3.3. Real-Time Balancing and Ancillary Services

Balancing and Ancillary Services are processes and products that are deployed in real-time—what one might call the operating horizon, when physical transactions occur as opposed to forward schedules. Day-ahead scheduling and market coupling identify the units that are committed to supply the market with energy and reserves for the operating day. However, to operate the market securely in real-time, TSOs must ensure that enough resources are available, given any changes in system conditions from the day-ahead, and that they are dispatched on a moment-to-moment basis in a manner that maintains system balance and security.

The development of separate ancillary services markets was necessary due to unbundling TSOs from generation assets that were formerly used by vertically integrated companies to keep their systems in balance. With unbundling, TSOs lose direct control over the generation assets they had at hand, internally, in the old vertically-integrated company. To keep the electricity system balanced, they need the ability to call on identified generation assets or demand-side assets to do the critical job of balancing the system. This is also important because harmonized ancillary services need to be in place to facilitate core elements of cross-border trading—for example scheduling, balancing, and losses procurement. Ancillary services are products offered or facilitated by the TSO that preserve power quality and balance on the system and thereby allow multiple users to utilize a transmission network while preserving system security.

2.3.3.1. Balancing versus Ancillary Services

The language used to describe ancillary services, balancing, and imbalance is not always consistent across localities. One of the important aspects of the EU IEM is to harmonize network operating practices, including how to define balancing, ancillary services, and imbalance. This section provides a technical discussion of these issues, including definitions and ways to develop prices and related policies.

"Balancing" is a process, while several ancillary services are products to be defined and supplied. Balancing and ancillary services are often discussed together because they are core functions of TSOs. . Some ancillary services are part of the balancing function in that they are processes needed to ensure continuous balancing of the system. Other ancillary services (e.g., black start), are necessary for grid operation and security, but not necessarily for the balancing process.

For the purposes of the Black Sea Market Integration, the structure of ancillary services as defined by ACER provides a good basis for establishing standard products. According to ACER, ancillary services are defined as services necessary to support the transmission of electric power between generation and load, maintaining a satisfactory level of operational security and with a satisfactory quality of supply.[14] The collection of ancillary services is used to support transmission services and is primarily designed to ensure system security through operating reserves, voltage support, and black start.

In the ENTSO-E Network Code for Operational Planning and Scheduling, Ancillary Services refer to Active Power, Reactive Power, and Black Start. The first of these two enables the TSO to operate a secure and reliable power system, whereas the last enables the TSO to reset the system after a system breakdown. In managing the transmission systems, the TSOs must be able to deal with unexpected changes of generation capacity, interconnector flows, or system demand. This is accomplished by maintaining a prudent level of active power ancillary services. For reactive power, the TSOs must maintain a voltage balance across the network to maintain a secure and stable power system and to avoid damage to connected equipment.

Ancillary services associated with active power reserves are the primary means by which TSOs react to moment-to-moment fluctuations and unanticipated imbalances. The ENTSO-E network code for Energy Balancing defines three types of Balancing Services based on their function. Appendix II provides more formal definitions.

The term balancing is used herein in the same way as ACER has defined it:

> All actions and processes through which TSOs ensure that total electricity withdrawals are equaled by total injections in a continuous way, to maintain the system frequency within a defined stability range.[15]

As introduced above, *balancing* is a process, and not a particular product or action. Within the balancing process, there are individual products and services, including ancillary services. For example, *balancing reserves (or Balancing Capacity or Reserve Capacity)* are ancillary services that refer to the idle capacity the

[14] ACER, "Framework Guidelines on System Operation," 2014)

[15] "Initial Impact Assessment for the Framework Guidelines on Electricity Balancing," ACER, September 18, 2012, p.1.

TSO keeps on hand to meet unexpected imbalances between scheduled and actual load and generation. *Balancing Energy* is the actual use of this capacity, which may be produced from set-aside reserve capacity that the TSO may procure from market participants or neighboring systems. *Balancing Services* means either or both Balancing Capacity and Balancing Energy.

Imbalance Settlement reflects the amount charged or paid to a participant that relies on the balancing mechanisms or supplies the balancing services. Imbalance can be thought of, roughly, as the real-time energy markets where the balance responsibly party (BRP) makes up for its deviation from forward schedules (e.g., day-ahead schedules). A BRP with resources dispatched above or below its actual load creates an imbalance settlement, which is the essential element of the balancing markets. A short imbalance settlement (a BRP whose dispatched resources are less than its actual load) pays the imbalance price, while a long imbalance settlement (a BRP whose dispatched resources are greater than its actual load) receives the imbalance price. Imbalance prices are formed through the market mechanism, which are to be based on bids and offers for supplying and buying balancing energy. Each TSO is responsible for establishing rules to calculate the balancing energy price, and regulators have the responsibility to approve such rules. In this process, the offers and bids for balancing energy and the imbalance settlement are for the energy only. The typical arrangement is for the TSO to have contracted for ancillary services capacity (reserves) in advance, and the contract requires the units supplying the ancillary services capacity to stand ready as reserves and to be paid for any balancing energy supplied. In more advanced arrangements, the ancillary services capacity could be procured on a day-ahead basis (the current US practice). Balancing energy may also be supplied by resources even if they do not have a reserve contract, provided they are technically capable.

As emphasized above, initiating processes and rules for cross-border trading along with balancing and ancillary services to support the cross-border trading is the essential focus in establishing further regional and sub-regional integration. Moreover, the ancillary services and balancing functions should at least partially reflect the liberalization policies of the IEM. Initially, as discussed below, participants can focus on moving power across their borders in pragmatic ways to exploit existing opportunities and to get used to the mechanics of such trading. This will establish the rudimentary mechanisms upon which the more advanced, market mechanisms can be built. Fully deregulated wholesale markets can require many years before they are realized. Even with the Stabilization Pact of the 1990s and the Energy Community Treaty, South East Europe has worked for more than 10 years to complete wholesale and retail market openings, and they are still not on the immediate horizon. However, South East Europe Energy Community signatories have cooperated to establish planning and scheduling mechanisms to enable cross-border trading, and countries trade on a regular basis there.

The Black Sea Market Integration effort concentrates on advancing processes and results in cross-border trading and balancing and ancillary services. But this does not mean it will ignore the harmonization process of the EU Third Energy Package. In fact, as noted elsewhere, the basic mechanisms established for the Black Sea Market Integration (cross-border transmission capacity allocation and congestion management, grid connection, system operation, and harmonized transmission tariff structures) will form the building blocks for the fully harmonized system. The Network Codes on Balancing are the final network codes and the ones that most directly require standardized, market-based trading rules.

2.3.3.2. Certification and Oversight of Ancillary Services Providers

In this section, we address how regulators identify and oversee Ancillary Services Providers, using Hungary as a reference case. Generally, providers of ancillary services will be generating resources. In some cases, load that can quickly curtail its usage could also provide resources, but in general, the main regulatory challenge is overseeing the generating resources that provide ancillary services. TSOs must prequalify entities as Balancing Service Providers (BSPs), and regulators must oversee such processes.

To be transparent and eliminate entry barriers, every condition and necessary piece of information are defined in the Grid Codes, which were introduced during the market introduction. The Grid Codes include every technical requirement of the Hungarian electricity system relevant to the TSO, while the Commercial Code includes every market and commercial based requirement. Finally, there is an additional Code (code of Business Conduct), which includes all the templates of the Framework Agreements for each balancing services, which define every contractual issue from the aspect of BSP and TSO.

As discussed above, there are three types of ancillary services defined under EU reform: primary control, secondary control, and tertiary control. All three services are distinguished by both quantitative and qualitative requirements. Please see Appendix II for technical definitions. Regarding the quantitative requirements, it is worth mentioning that there is a system requirement (total amount of the service available in the system) and an entity-based requirement (such as minimum amount the entity is able to provide):

Primary control for frequency containment is supposed to compensate for an imbalance between generation and consumption locally and automatically within a few seconds. The Continental European system requirement is 3000 MW of total power supplied or withdrawn, and this amount needs to be continuously available. All control areas make their contribution to this total amount based on a common, centralized calculation (quantitative requirement).

Secondary control for frequency restoration is a centrally and automatically-activated service, which is supposed to relieve primary control so that it can resume its function of securing the system. Secondary control is activated when it is assumed that the system will be affected for a period longer than 30 seconds. The minimum required quantity is based on the dimensioning requirements in the Network Codes.

Tertiary control for replacement reserves is a centrally and manually activated service in cases where the deviation in the control area lasts more than 15 minutes (qualitative requirement). Tertiary control is used to relieve secondary control to make it available again. In the Hungarian system, in line with the European regulation, this minimum amount is the largest power plant unit, which can be unexpectedly out of operation.

An entity can provide any of these services after a prequalification (accreditation) process. This is a technical certification procedure, which examines whether the entity has the technical ability (qualitative) and the capability (quantitative) to meet the criteria required to guarantee the respective ancillary service. This certification has to be carried out for each type of balancing service individually, since the requirements are not the same for all.

The prequalification (accreditation) process has to be initiated by the entity (or the BSP) and has four main steps, strictly following each other in order. The entire procedure requires continuous communication between the initiating entity and the TSO. The first step is the preparation of parameters regarding the relevant service. The aim of this step is to identify and agree on every technical requirement, basically the technical limits within which the respective service can be provided (i.e. minimum power generation, maximum power generation), the total amount of capacity which can be provided for the respective service, the necessary time to react on a request, and the speed of control activation. The agreed technical parameters are set down in prequalification documentation.

Beyond the technical data, the documentation also contains the level of participation in balancing (whether it is in a generator group or is an individual generating unit), the identifiers of the generating units, the settlement point, and the balance group. The second step is an offline testing, whether the parameters and technical background (mostly data communication and necessary IT background) can be completed and can work properly. Upon successful accomplishment of offline testing, the third and most important step, the "live" testing phase, takes place. This begins with the common preparation of testing scenarios and continues with real testing of the agreed scenarios. These scenarios have to be able to identify every requirement, which is necessary to prove that the entity is able to provide the respective service. Finally, the last step is the evaluation of testing results, including a discussion between the TSO and the initiating entity. The TSO has to have its own monitoring devices and measurements, which correctly represent the results. At the end of this evaluation, which should be conducted within 90 days, the prequalification documentation is finalized and mutually signed by both the initiating entity and the TSO. The results of this process should then be reported to the regulator for approval. The validity of the prequalification documentation can last for a maximum of 3 years, after which point it has to be renewed. Once there is a prequalified BSP, the next step is to commonly sign a framework agreement, which enables participation in the balancing market.

Power plants that already existed at the time of unbundling could voluntarily decide whether to invest in ancillary services.[16] However, in a well-functioning market, price signals would motivate them to take part in these markets. For new units, however, there are predefined criteria to provide each of the ancillary services. Furthermore, all market participants providing ancillary services are obliged to place bids in tenders organized by the TSO for the procurement of balancing capacity or energy. In Hungary, exemption is only possible in cases defined in the Hungarian Electricity Act (e.g. maintenance, technical disturbances, lack of non-used capacity, market prices do not cover variable costs). However, those entities that do not want to take part in balancing activities because of other reasons still have the possibility to bid high prices to not to be selected. In case they do not perform their bidding obligations, the Energy Regulatory Authority has the right to impose a penalty on them.

For the TSO, it is essential to be able to monitor whether the requested service on balancing market is completed. Real-time evaluation and/or ex-post evaluation procedures are applied, representing whether the requested service was completed from both qualitative and quantitative aspects. These are basically metering tools that indicate at what level and at what time the unit was providing energy to the grid or was online and providing reserves. In case a participant was non-compliant, the concerning BSP is obliged to pay a penalty (typically the cost of substitution of the service non-supplied, but in some countries, there could be additional penalties on top of the replacement costs). The TSO also has the possibility to test the availability of the entities contracted as reserve capacities even if they are not activated during the balancing process. The TSO has the right to carry out a testing process at any time but maximum nine times during the contracted period. In case the contracted reserves are not available a penalty (20 percent of total capacity fee during the period of unavailability) must be paid to the TSO.

[16] This raises the question regarding the proper incentives to participate in providing these services by resources, especially in the early stages when rates and terms of service may be uncertain. Regulators would have the authority to compel participation by qualified resources, but this would be inferior to a process where rates are fully compensatory. Until markets are developed, regulators should seek mechanisms and rates which do not overcompensate, but which also provide incentives for resources to participate.

2.3.3.3. Guidelines on Next Steps for Balancing and Ancillary Service

Regulators should adopt common positions on balancing and ancillary services definitions as identified in Appendix II. This should involve agreeing to the technical definitions and recognizing them as the objective within each country's liberalization process.

- A key step in developing balancing and ancillary services markets is to harmonize the definitions of the products used so that eventually they may be traded on standardized basis. The standardized definitions used in the Network Codes should be the basis of this effort. The main definitions used in the Network Codes for balancing and ancillary services are reflected in Appendix II on Balancing and Ancillary Services.
- Regulators should begin working with TSOs to discuss the harmonization of technical requirements for balancing and ancillary services among regional participants.

Balancing and ancillary services are provided essentially by maintaining extra generation capacity (or load-responsive resources) on the system during the operating horizon (real-time). As discussed above, the type of generation to be reserved depends on the balancing and ancillary services requirements and is a technical issue addressed in the Network Codes. Essentially, the capacity must be flexible and have automated dispatch capabilities. The exact level of reserves and the technology required for ancillary services involve highly technical engineering topics that would best be addressed in conjunction with TSOs. These various engineering requirements are described in the System Operation Guideline, which is a merger of three individual Network Codes.[17]

2.3.4. Cost-Based Pricing

It may not be advisable to move directly to market-based pricing of balancing and ancillary services for most countries in the BSRI. However, regardless of the degree of integration with neighboring countries and regardless of the degree to which a country has liberalized its wholesale markets, balancing and ancillary services must be supplied to the system to maintain its stability. In the case of a single asset owner and operator of transmission and generation, balancing and ancillary services are not considered "services," but merely operational actions to maintain system security. Balancing and ancillary services become "services" when the grid operator must provide them to ensure stability in the presence of multiple users of the grid. The quality of the service also must be better defined when the system is open to cross-border trading and wholesale transactions.

Pricing ancillary services on a market basis requires effective market structure and performance. In the Black Sea region, the markets are not yet ready to support competitive outcomes for balancing and ancillary services. Even though efficient and effective wholesale competition is a critical goal, until competitive wholesale markets are in place, TSOs in the region will not have market mechanisms ready for ancillary services and balancing products at the outset of reform.

<u>This creates the need to address three main issues. The first is the preconditions for participating in ancillary services supply at cost-based rates. The second issue is how to develop cost-based rates for ancillary services and balancing. The third issue is how regulators determine when the market is ready for market-based procurement and how to monitor such markets.</u>

[17] https://www.entsoe.eu/major-projects/network-code-development/system-operation/Pages/default.aspx

2.3.4.1. Preconditions for Cost-Based Rates

Cost-based rates are a transition mechanism that facilitates the provision of clearly defined ancillary services at transparent regulated rates. But even this transition step must be taken only when the regulatory structure is adequate to allow development of the regulated products.

In countries embarking on liberalization, ancillary services are usually provided by the dominant generating company and often for free. This is understandable and expected in some systems where main facets of the electricity industry were comprehensively regulated as a single enterprise. Hence, even moving to cost-based rates for ancillary services requires certain first steps.

These first steps include:

(1) Define, precisely, the ancillary service to be provided;
(2) Identify technical requirements for providers seeking to supply the ancillary services (see detailed discussion above in section 2.3.3.2); and
(3) Certification or licensing of suppliers by regulators based on technical requirements.

Once the certification process is completed, the costs associated with technical requirements can be better defined, such as the cost of remaining in service for the year, the cost of remaining online each day and the cost of supplying energy to the grid.

2.3.4.2. Cost of Service

Ancillary services and balancing are generally provided by generating resources, although they can also be provided by load-response resources (consumers that are able to reduce their consumption through a signal from the TSO). For generating resources, the cost of providing balancing and ancillary services is essentially the cost of supplying generation, and there are two main types of generation costs. One type of cost is for capacity, which is used to supply reserve-based ancillary services (primary reserves, secondary reserves, etc.). The other type of generation cost is "running" costs, sometimes called variable costs.

Capacity or Fixed Costs

Capacity costs are the fixed costs of keeping a unit in service, but not the cost of actually operating the unit to supply power. At a very basic level, capacity costs are the costs required to keep a unit in service plus an allocation of the costs of paying for the unit's historical unrecovered construction or acquisition costs. Because reserves are using the generation resources to stand ready, the underlying cost of reserves is the capacity cost.

Running or Variable Costs

Variable costs are the costs of actually producing electricity from a resource. Running costs are mainly the cost of fuel, but there are also smaller amount of variable operating costs, such as labor and other operating expenses that change with output of the resource. When the TSO actually deploys reserves, balancing energy is produced, and the costs are based on the running costs. Running costs are somewhat simpler to estimate than capacity costs because running costs are largely fuel-related. Essentially this is fuel cost multiplied by the plant transformation rate, referred to as the "heat rate." The calculation provides the fuel cost per MWh of production. The running costs also include smaller amounts of variable operation and maintenance and some variable cost adders associated with carbon and other taxes. However, in the case of hydroelectric plants, there is no fuel cost. Instead, the running costs are based on the avoided fuel of fossil-fuel units when hydro units are operating. This is the so-called "opportunity cost" approach for establishing the running costs for hydro and other renewable resources.

Cost-based balancing and ancillary services were the first steps taken by the US Federal Energy Regulatory Commission when it required open access to all US utilities' transmission lines. Essentially, the utilities were required to provide standard balancing and ancillary services at cost-based prices. Those prices had to be published in the utilities' open-access transmission tariff and justified through a cost-of-service study. The balancing and ancillary services were included in the transmission price charged to users for using the utility's network. Cost-based ancillary services allow the TSOs to establish rates and specifications of the various products, without having the confounding challenge of ensuring effective competition in supplying them.

Of course, regulators have critical oversight of these products and the rates, terms, and conditions of service.

Opportunity Costs. As noted above, some resources experience "opportunity costs" when providing certain services. The classic example is the case of a hydroelectric plant providing energy. The variable cost of providing energy from a hydroelectric plant is close to zero—i.e., simply release water from the reservoir, and the turbines spin and produce electricity. However, there can be a lost opportunity associated with releasing energy from the plant at one point in time versus releasing energy at another point in time. This lost opportunity is the opportunity cost. For hydro plants, this is often calculated as the marginal cost of producing system energy during peak hours. Typically, the most expensive MW produced during the year is during the peak hour. It is this time when all lower cost resources are already dispatched and the system operator calls on increasingly expensive units to satisfy demand, usually fossil fuel units. In the peak hour, the hydro unit can relieve the system of that incremental cost if it were to release energy from its reservoir at that peak time instead of the system operator ramping up a fossil fuel plant. Therefore, the opportunity cost of dispatching a hydro unit in an off-peak period is the lost opportunity of using the reservoir for a MW produced during peak hours.

Opportunity costs may also occur when units are asked to remain idle to provide operating reserves. In such cases, the unit is not able to sell its energy and the regulator may compensate the unit by calculating the missed opportunity. This calculation would be the energy price that prevailed during times when the unit was selected for reserves less the unit's savings in fuel cost from not producing. (The unit should also be eligible for cost-based compensation for cost incurred while idle, such as starting up and operating at a minimum generation level to respond to any reserve deployment).

A good example of applying opportunity cost to cost-based pricing is on the Serbian system. At the November BSRI workshop, Mr. Aca Vučković from the Serbian regulator, AERS, presented on ancillary services pricing, which includes an opportunity cost component. In addition to the ancillary services rates reflecting costs associated with specialized equipment to respond to an ancillary services deployment, a main component of both secondary and tertiary reserves is "loss of revenue" from the supplier holding capacity in reserve. The loss of revenue is calculated in advance based on the anticipated hourly reserve requirements and anticipated market prices during each hour of the next year. First, based on anticipated demand and reserve needs in each hour, the regulator calculates total reserves that are anticipated to remain idle during the year (this is adjusted by an estimate of balancing energy expected to be deployed from them). Next, this total expected idle capacity is multiplied by the expected weighted average price in each hour (weighted by reserves procured in each hour). This value represents the anticipated total lost revenue to units holding reserves. This total is divided by total reserve MWh anticipated to determine the opportunity cost rate component.

Developing Cost-Based Rates. There is a long history of cost-of-service regulation in the US and Europe that identifies capacity costs and running costs that can assist regulators in developing costs-of-service rates for capacity.[18] Cost-of-service is essentially the amount of revenue a regulated utility must collect to recover the cost of supplying a regulated product. The total cost of service allows the regulated utility to cover its operating and capacity cost, including a return on invested capital. <u>Cost-of-service principles would be the basis for developing cost-based balancing and ancillary services</u>.

The cost of service for a regulated asset is made up of two types of costs: operating costs and capacity costs. Operating costs, sometimes called variable costs, are the costs required to actually operate the regulated asset. These will include, mainly, variable operation and maintenance (called Variable O&M and include labor, fuel, and certain overhead expenses), and output-related taxes, like income taxes. Generally speaking, these are costs that would be avoided if the asset was idle, but still in service. Capacity costs, sometimes called capital costs, are costs associated with paying for the construction or acquisition of the asset, cost of upgrading the asset, and fixed costs of keeping the asset in service (overhead and Fixed O&M). Capacity costs are incurred even if the asset does not produce.

The general formula for cost-of service is:

Total Cost of Service = Variable Costs (variable O&M + variable taxes) + Capacity Costs (fixed O&M, fixed overhead costs, return on investment, and return of investment).

Operating costs: For generating resources, the main operating costs are not only fuel costs, but also taxes, maintenance, and overhead costs that change when the output of a unit changes. The task of the regulator is to identify these variable costs for a given "test year" and divide this total test year variable cost amount by the total volumetric (MWh) output of the asset to arrive at the per MWh cost-of-service. This is the average variable cost: *total annual variable cost/total annual output*. The key is to account for total costs over some period (test year) and then divide this by the total output during that test year.

For units restricted in output, such as a hydro unit that must optimize its reservoir levels, the cost of operating includes the foregone loss of revenue from not operating in other periods. This is sometimes a difficult question if the unit does not have lost opportunities, such as when there is not a well-functioning market to determine the lost opportunities.

Capacity Costs: In addition to fixed costs, which are the costs of maintaining physical productive assets even when they are not operating, capacity costs also include the *return on* and *return of* investment. Both return of investment and return on investment are based on the initial plant investment and subsequent investment upgrades. Return of investment means collecting a portion of the total investment, known as depreciation expense. Depreciation expenses are typically the total cost of the asset (initial cost plus any incremental upgrades) divided by the number of years it is expected to last—usually 30 years for utility plants. Depreciation expenses are the return of investment.

At any point in time, total investment less any depreciation expenses already recorded (called accumulated depreciation) is the "net book value." The *return on* investment is net book values times the utility "cost-

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[18] *See, e.g.*, Federal Energy Regulatory Commission, "Cost-of-Service Rates Manual," June 1999. *"Electricity Class Cost of Service Studies," produced for ERRA Tariff / Pricing Committee, by Denise Parrish Office of Consumer Advocate Wyoming Public Service Commission, 2012.*

of-capital." Cost of capital is the cost of borrowing capital from debt and equity markets for the utility's investments, hence: return on investment = net book value x cost of capital.

This discussion of cost of service is very general and only establishes the very broad categories of costs and how they are treated in the ratemaking process. However, it provides a basis for understanding the first steps in establishing cost-based rates for regulated utility products.

2.3.4.3. Cost-of-Service Rates

When developing a rate for ancillary services, both variable and capacity costs are important. Ancillary services are mainly capacity products providing reserves. The contractual relationships between the TSO and the capacity resource ensure the availability of the capacity, but not energy. The contractual mechanism could be months in advance, or it could be procured in a multi-lateral, day-ahead auction. The longer-term monthly or annual contract is the typical first step in the development of the ancillary services procurement mechanism for TSOs under the EU reforms, whether it is a cost-based or a market-based mechanism. The resources under contract typically will have the obligation to be on line during the operating day to provide the ancillary services. They are paid the ancillary services rate whether they are providing balancing energy or not.

The ancillary services rate for each resource will correspond to the individual capacity costs:

Ancillary Services Rates – The monthly rate for an ancillary services reserve product should be based on the fixed cost of remaining in service per MW year, and then divided by the term of service within the year.

Annual Rate = Capacity cost of remaining in service/MW

Monthly Rate = Annual Rate/12

Weekly Rate = Annual Rate/52

Note: Deployment of reserves would be paid an energy rate calculated in the same manner as the Balancing Energy rate; Annual fixed cost is for the capacity capable of providing the specific reserve, which might include specialized equipment for meeting reserve technical requirements (AGC, for example).

Balancing Energy is procured by the TSO in real-time from Balancing Service Providers. These can be resources selected in the day-ahead time frame to provide Balancing Capacity in accordance with the "dimensioning" requirements. Other market participants can also provide Balancing Capacity as long as they have balancing-capable resources and are on line in real-time.

Dimensioning refers to the amount of reserves needed on a given system. For example, (Secondary) Frequency Restoration Reserves typically correspond to the largest plant on the system (must be ready to recover for the loss of the largest plant on the systems). (Tertiary) Replacement Reserves are typically equal to the value of Secondary Reserve (Replacement Reserve must be able to replace the Secondary Reserves in the event of the largest outage). Dimensioning is conducted by the TSO on at least an annual basis.

In the operating time frame (real-time), the TSO will dispatch available Balancing Capacity to maintain the instantaneous balance between generations and load while at the same time maintaining secondary reserves (Primary reserves are widely installed on all units so there is typically no need to ensure adequate capacity for primary reserves in real-time).

The vast bulk of real-time energy will be supplied by participants in accordance with their day-ahead schedules. However, if an unexpected outage occurs or load is higher or lower than expected, or a participant simply under or over performs their day-ahead schedules, the system will constantly need a small amount of energy to dispatch up or down. The TSO provides this Balancing Energy by dispatching Balancing Capacity.

The TSO selects Balancing Energy based on merit-order bids. The merit-order bids should be based on the short-run operating cost of the resource, mainly the fuel cost. Therefore, each unit should have a rate calculated as follows:

Balancing Energy Rate – The rate for balancing energy should be based on the variable cost of providing energy from an in-service unit. This is a short-term rate (less than one year) and so does not include capacity payment:

Rate = Total Variable Cost during term of service/Total Output during term of service,

Where term of service is the period over which the rates are developed, usually a year.

Balancing energy is deployed because of schedule imbalances from the day-ahead (or intra-day) or because of an outage. Because regulators like to provide incentives to avoid over and under scheduling and to avoid outages, the balancing energy rate is sometimes increased to reflect a penalty. For example the rate may be 110 percent of the cost-based rate or higher.

2.3.4.4. Ancillary Services Payments and Imbalance Settlement

The discussion of ancillary services rates and imbalance settlement so far pertains to what each individual supplier would be paid. The next issue is who pays for these costs. Essentially, in a cost-of-service regime, the costs are allocated to all users based on usage. On an hourly, daily, or monthly basis, the cost to the TSO of procuring ancillary services must be paid for by the system load. As a result, the TSO must charge network users for the cost of ancillary services. The allocation is the total ancillary services cost divided by each user's share of the system usage during the term of service. For example, if the allocation is on an hourly basis, the hourly payments to Ancillary Services Providers is divide among all system users in proportion to each user's share of system MW demand. A more detailed example of cost-based ancillary services is provided in the Appendix II on Balancing and Ancillary Services.

2.3.4.5. Guidelines on Next Steps for Developing Cost-Based Rates

- TSOs should be required to develop cost-based rates for ancillary services.

  As introduced above, TSOs may not have markets available to procure ancillary services. Hence until the time comes when markets are workable and can provide these services effectively, cost-based rates are the appropriate approach.

- The role of the regulator is to approve cost-based rates and then to determine when the market is developed to the point where the TSOs can perform market-based ancillary services procurement.

  In the market monitoring subsection (section 5.), we address how regulators can measure when a market is ready for competition and how to monitor the market.

2.3.5. Competition, Market Power, and Market Monitoring

Market power is the ability of a single market participant (or a group acting together) to control the price of a product by restricting supply. The presence of market power is one of the main concerns about the effect of liberalization, particularly in national markets where an incumbent continues to control a large portion of the generation assets.

A chief tool of the liberalization process is reliance on competition to improve the efficiency of generation supply (balancing and some ancillary services). However, if market power exists, relying on competition will not be effective. Market power can be addressed by effective market monitoring. Market monitoring is a function of regulatory authorities under the Third Package that seeks to ensure the market is *operating* effectively and efficiently. Properly implemented, market monitoring can be used to control market power.

Appendix III on Market Monitoring provides a summary of the main provisions from the EU regulations on this topic. The regulators' market monitoring authority includes the power to *detect and prevent* market manipulation (see Regulation (EC) 1227). The Black Sea regulators, when the time comes to rely on competitive markets, should use their authority to "prevent" market manipulation. This could take the form of offer cap for suppliers that have market power, thereby preventing the exercise of market power. This type of market power mitigation is common in the US and has been effective.

2.3.5.1. Guidelines on Next Steps for Market Monitoring

2.3.5.1.1. Balancing and Ancillary Services Market Monitoring

- Regulators should begin calculating market shares in accordance with the process outlined in Appendix III.

  As explained above, procuring ancillary services and balancing energy based on cost of service can be used effectively in transition to a market-based method. This is when there are "sufficient" independent and competing providers for the various services. Appendix III on Market Monitoring shows an example of the market share analysis used in the US to determine whether market-based pricing is justified in a market.

- Also as a next step, regulators could establish a market monitoring function within their regulatory agencies to monitor the market structure of the ancillary services and balancing markets.

  When multiple suppliers are available to compete and to supply ancillary services and balancing, a competitive mechanism can be introduced where suppliers freely offer at unregulated prices. The market monitoring function is important in this regard because the market would need to be analyzed for market power before it would be prudent to allow competition to set prices.

- Regulators can begin estimating offer caps based on the cost of service and mitigation would be applied to suppliers that have market power.

  Once competition is allowed in the balancing market, offer caps would serve to establish market power mitigation measures if some level of market power prevails. In this way, a supplier with market power would not be able to raise prices above the cost of service. As discussed above in Appendix III on Market Monitoring, the EU Third Package of reforms[19] empowers regulators to take preventive measures to address market power. As such, a cap on offers by suppliers with market power would prevent offers that are above competitive levels. The offer cap would be a cost-based value that the dominant firm or firms could not exceed in offering to supply the market.

2.3.5.1.1.1. Mexico Example – Offer Caps

One useful example in this regard is the liberalization process currently taking place in Mexico. Mexico is embarking on a wholesale market liberalization that will require all generators to offer into a multi-lateral power market. The basic structure is one in which lowest-offered resources are dispatched to serve load in each hourly market interval. The generators whose offers are low enough to be selected are paid a price equal to the highest offer among selected generators. When there are many small suppliers, this structure (sometimes called pay-as-cleared or single-price) creates strong incentives for an individual supplier to offer its power at the short-term marginal cost to ensure it is dispatched at a price equal to or higher than its marginal costs. When the market is less competitive and one or more suppliers dominate the market, there may be incentives at times to offer into the market above the suppliers' true costs.

To prevent such behavior, market power mitigation measures are employed. In Mexico, suppliers are restricted to offering at 110 percent of their short-run marginal cost. These short run marginal costs are submitted by generators subject to review by the regulator. These offer caps are across the board, meaning all generators regardless of size are required to submit costs and are subject to the offer cap.

In US markets, the offer cap is sometimes restricted to generators that have market power, measured by various metrics – e.g., by determining if the generator's offer will influence the price significantly. The approach in Mexico is to place offer caps on all generators, without determining whether the generator has market power. This is a reasonable approach given they are in the transition period to market liberalization.

2.3.5.1.1.2. Monitoring Cross-Border Transmission Capacity

- National regulators must have authority to oversee the calculation of cross-border capacity and have access to the assumptions and models used by the TSO to calculate cross-border capacity.

The discussion of access to cross-border capacity in section 2.2 focused on the rules and procedures for enabling third-party use of the system. One element of cross-border trade that was not treated above was the how cross-border capacity can restrict market competition. Therefore, in addition to market monitoring of generating resources already discussed above, regulators should monitor the cross-border capacity market to help ensure effective market development. The USAID-supported work in South East Europe provides a good example of an approach for monitoring the cross-border capacity market. Essentially, the job of the regulator is to make sure the TSOs provide adequate capacity to the market and to make sure participants do not over-reserve the capacity to keep it away from

[19] Regulation (EC) No. 713/2009, Article II.

competitors. Cross-border monitoring responsibility under EU regulation is discussed in Appendix III on market monitoring.

2.4. BEST PRACTICES FOR INTEGRATION OF RENEWABLES

Renewable energy resources present significant value to electric system because they represent ways to meet national environmental goals, especially carbon reduction goals, provide a source of domestic production capacity (and thus energy security), and they have become more economic relative to traditional sources of electricity. Renewable integration is an important element of the EU Internal Energy Market because it has been identified as a key priority in the energy reform packages. In particular, integration of renewable resources was made a priority for the IEM under Directive 2009/28/EC[20] of April 23, 2009. In this directive, the EU established binding renewable targets for all Member States, such that the EU will reach a 20 percent share of energy from renewable sources by 2020. It also set related policies for integration of the renewables into the grid, which is a key concern for wholesale market development.

At paragraph (57), the directive specifically identifies the need to "support the integration of energy from renewable sources into the transmission and distribution grid."

Article 16 sets out the policy regarding integrating renewables into the grid (Article 16 is titled "Access to and Operation of the Grids"):

> *Member States shall take the appropriate steps to develop transmission and distribution grid infrastructure, intelligent networks, storage facilities and the electricity system, in order to allow the secure operation of the electricity system as it accommodates the further development of electricity production from renewable energy sources, including interconnection between Member States and between Member States and third countries. Member States shall also take appropriate steps to accelerate authorisation procedures for grid infrastructure and to coordinate approval of grid infrastructure with administrative and planning procedures.*
>
> *(a) Member States shall ensure that transmission system operators and distribution system operators in their territory guarantee the transmission and distribution of electricity produced from renewable energy sources;*
>
> *(b) Member States shall also provide for either priority access or guaranteed access to the grid-system of electricity produced from renewable energy sources;*
>
> *(c) Member States shall ensure that when dispatching electricity generating installations, transmission system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria. Member States shall ensure that appropriate grid and market-related operational measures are taken in order to minimise the curtailment of electricity produced from renewable energy sources. If significant measures are taken to curtail the renewable energy sources in order to guarantee the security of the national electricity system and security of energy supply, Members States shall ensure*

[20] DIRECTIVE 2009/28/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

that the responsible system operators report to the competent regulatory authority on those measures and indicate which corrective measures they intend to take in order to prevent inappropriate curtailments.

Additionally, the EU envisions the possibility of subsidizing the integration of renewable resources:

Article 16 (3) Member States shall require transmission system operators and distribution system operators to set up and make public their standard rules relating to the bearing and sharing of costs of technical adaptations, such as grid connections and grid reinforcements, improved operation of the grid and rules on the nondiscriminatory implementation of the grid codes, which are necessary in order to integrate new producers feeding electricity produced from renewable energy sources into the interconnected grid.

2.4.1. Guidelines on Next Steps for Integration of Renewables

The EU policy on renewables establishes a goal of achieving a level of renewables generation that is at least 20 percent of total generation by 2020. Prior work on integrating renewable resources in the Black Sea is relevant for this current project. Appendix IV provides principles on Renewable Integration that were developed in previous BSRI projects. The following are the key principles from the Appendix IV that regulators should attend to in the immediate term as next steps. (The paragraph reference numbers correspond to the paragraph numbers from Appendix IV.)

Key Principles for next steps in renewable integration:

(3) [A]n important regulatory task related to renewable energy sources ("RES") is to develop an effective incentive regulation to remunerate RES-related network investments. Such regulation should include a method to define and allocate connection and network upgrade costs among RES producers, network companies, and final customers.

(7) Based on this principle, European regulators propose that charges for connecting to and using the system should, in principle, be transparent, cost-reflective, and not dependent on the source of the electricity.[21] Such a regulation will encourage developers to carefully evaluate the trade-offs between RES quality and the cost of connection.

(9) Regulation can also decide to partly or fully socialize the cost of connection and grid upgrade, to facilitate the satisfaction of RES policy objectives. Socialization in this context means that retail customers, instead of developers, pay, in the form of network or end customer tariff increases, part or the full cost of network expansion to integrate RES into the grid connection and access.

(16) Technical standards for the connection of RES producers should be established by grid operators and approved by the Regulator, e.g. as part of the TSO transmission tariff. Such technical standards should be transparent, easily available for investors, and should strike the right balance between system reliability needs and simplicity to promote RES penetration.

(25) To ease the stress on system balancing [from difficult-to-control resources], the Regulator should establish incentives both for intermittent RES producers to provide improved forecasts of their future production to the system operator and for the system operator to allow those producers flexibility in adjusting their forecasts as better weather forecast information becomes

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21 (original footnote 4) Regulatory aspects of the integration of wind generation in European electricity markets. A CEER Conclusions Paper, Ref: C10-SDE-16-03. 7 July 2010, pp. 20-22.

available to them. There could also be a third-party forecaster that assists the grid operator in maintaining accurate forecasts.

(28) Because of the uncertainties of weather forecasting, the combination of a long lead time for the mandatory scheduling (e.g. month, week, or day-ahead) and high imbalance charges might undermine the profitability of intermittent RES producers. For this reason, the regulator should ensure that the system operator allows these producers to adjust their schedule intra-day as close to real time as possible.

3. GOVERNANCE

To sustain coordination among Black Sea regulators to advance wholesale market development and integration, a governance structure should be agreed upon that will guide further work. While the outline of a governance structure should initially involve regulators, it ultimately should involve a range of major stakeholders in each country, including TSOs and ministries.

There is currently discussion about conducting joint meetings with Black Sea TSOs, which is a good first step. A commitment on the part of these two groups to continue meeting would be another step toward sustained coordination among key stakeholders.

The experience in South East Europe under the Energy Community of South East Europe provides insight into useful governance structures. Under the Energy Community, regulators meet among themselves in a permanent working group and develop task forces within the working groups for particular issues, for example balancing market issues or market monitoring. Likewise, TSOs meet in working groups and develop ongoing work within task forces. The energy community also has higher-level meetings among ministry-level representatives, to which the regulators and TSOs report. These stakeholder meetings and the ongoing work to achieve market development are critical to implementing the key steps in the liberalization and integration process. Appendix V describes the South East Europe Memorandum of Understanding that was the direct result of the Energy Community Process. As the appendix describes, the countries, including regulators, TSOs, and ministries, among others, have committed to very specific measures to advance the wholesale market in the region.

3.1. Black Sea Approach to Governance

The process in South East Europe is an example of regional cooperation that can be undertaken without formal agreements among countries. The MOU harmonizes the objectives of each country relative to market development, and commits them to a good faith effort to coordinate on a variety of issues that advance integration. For example, the MOU establishes that each country should have a balancing market, but the MOU is not a binding agreement, it only establishes what each should do in parallel to meet the goals of the MOU. It is a way to establish relationships and build trust and goodwill to support market integration.

The South East Europe MOU stands as an example of a possible way forward for the BSRI participants. In case the BSRI participants decide to coordinate development of the wholesale market from the regional perspective, they should agree to certain key positions. These positions include:

- Have regular joint regional meetings with TSOs and regulators to discuss key market development issues;
- Work with the Black Sea Transmission Planning (BSTP) project to establish bilaterally coordinated cross-border capacity estimates (NTC) for possible use in cross-border scheduling and to explore options for regional integration of balancing and ancillary services.
- Adopt common positions on balancing and ancillary services definitions as identified in Appendix II. This should involve agreeing to the technical definitions and recognizing them as the objective within each country's liberalization process. This does not commit the countries to adopt the definitions within the rules. Committing to adopt the definitions requires closer coordination with TSOs.

- To the extent the individual items are applicable, agree to adopt a common position endorsing transparency requirements as outlined in Appendix I.

These items essentially reflect some of the key next steps discussed above. However, to govern the advance of the regional integration, the above-listed items should be adopted explicitly among the BSRI participants. The numerous other next steps recommended throughout the report, should be adopted as specific circumstances develop in each country (as outlined in the individual country roadmaps).

In the event one or more participants cannot or will not agree to the coordinated actions, the other members can still agree on the principles while inviting the other participants to agree with qualifications or explanations.

GLOSSARY

ACER is Agency for Cooperation of Energy Regulators created under Regulations (EC) No 713/2009 and (EC) No 714/2009.

Ancillary Services are known in the industry as a collection of secondary services offered to support both system reliability and coordination. According to ACER, ancillary services are defined as follows:

> Ancillary Services [are] services necessary in support of transmission of electric power between generation and load, maintaining satisfactory level of operational security and with a satisfactory quality of supply. The main ancillary services include active and reactive power reserves for balancing power and voltage control. Active power reserves include automatically and manually activated reserves and are used to achieve instantaneous physical balance between generation and demand. Further ancillary services include black start and islanding capability. In the liberalized market, many ancillary services are procured by TSOs from the qualified and selected grid users, generators or loads (ACER, Framework Guidelines on System Operation, 2014).

Area Control Error (ACE) is the difference between scheduled and actual electrical generation and interchange within a control area on the power grid. It is used to monitor the individual balancing on interconnected systems.

Available Transfer Capacity (ATC) is the amount of cross-border transmission capacity that is still available for purchase. Technically, it is the Net Transfer Capacity (NTC) less the Already Allocated Capacity (AAC).

Balancing is the collection of actions and processes through which TSOs ensure that total electricity withdrawals are equaled by total injections in a continuous way to maintain the system frequency within a redefined stability range.

Balancing Energy is the actual use of this capacity, which may come for the set aside of reserves that the TSO may procure from market participants or neighboring systems.

Balancing Reserves *(or* ***Balancing Capacity*** *or* ***Reserve Capacity****)* is the idle capacity the TSO keeps on hand to meet unexpected imbalances.

Balancing Services is either or both Balancing Capacity and Balancing Energy.

Black Start Capability is the ability of a generating unit to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

Capacity Assessment is the process for estimating the cross-border transmission capacity between two interconnected countries.

ENTSO-E is the European Network for Transmission System Operators for Electricity created under Regulations (EC) No 713/2009 and (EC) No 714/2009.

Frequency Containment Reserves (Primary Reserves) are operating reserves necessary for constant containment of frequency deviations (fluctuations) from nominal value to constantly maintain the power balance in the whole synchronously interconnected system. These are deployed using Automatic Generation Control (AGC) within 30 seconds to regulate the frequency on a moment-to-moment basis.

This category typically includes operating reserves with the activation time up to 30 seconds. Operating reserves of this category are usually activated automatically and locally.

Frequency Restoration Reserves (Secondary Reserves) are operating reserves necessary to restore frequency to the nominal value after sudden system disturbance occurrence and consequently replace FCR if the frequency deviation lasts longer than 30 seconds. These are deployed both automatically and manually within between 30 seconds and 15 minutes when an imbalance arises to replace used up Primary reserves, deployed within 15 minutes).

Grid Codes (see Network Codes).

Imbalance is a settlement concept. It is the amount charged to or paid to a participant that relies on the balancing mechanisms or supplies the balancing mechanisms. Imbalance can roughly be thought of as the real-time energy markets that provide energy because suppliers under-supply or over-supply their day-ahead (or intra-day) schedule.

Interconnection is the set of transmission facilities connecting one country or control area to another.

Internal Energy Market is the vision for energy market liberalization that introduces competition by addressing market access, transparency, and regulation, consumer protection, supporting interconnection, and adequate levels of supply.

Islanding Capability is the ability to supply a grid area in isolation of the synchronous grid over extended periods of time, autonomously and with the aid of a generating unit, to maintain operation within the permitted operating parameters.

***National Regulatory Authorities* (NRAs)** are the national regulators responsible for regulating national electricity markets in accordance with the EU rules and legislation on the Internal Energy Market.

Net Transfer Capacity (NTC) is the amount of cross-border capacity that can be used for commercial transactions. Technically it is Total Transfer Capacity (TTC) less Transmission Reliability Margin (TRM).

Network Codes (synonymous with ***Grid Codes***) are a series of rules drafted by the ENTSO-E with guidance by ACER to codify the reforms in the EU directives on energy aimed at providing harmonized rules for cross-border exchanges of electricity (see, Regulations (EC) No 713/2009 and (EC) No 714/2009).

Network Model is a computer simulation of network operations used to estimate NTC by using assumed network conditions that accurately reflect transmission elements, load, generation, and exchanges between TSOs.

Open-Access is the policy that facilitates third-party access to the cross-border *interconnections* on a non-discriminatory basis.

Projects of Common Interest ("PCIs") are infrastructure projects aimed at helping EU member states to physically integrate their energy markets, thereby enabling them to diversify their energy sources and to help to integrate relatively isolated systems.

Replacement Reserves (Tertiary Reserves) are operating reserves necessary to restore the required level of operating reserves in the categories of frequency containment (FCR) and frequency restoration (FRR) reserves due to their earlier usage. These are deployed manually between 15 minutes and longer time frames to replace secondary reserves.

Total Transfer Capacity (TTC) is the maximum power transfer between two adjacent control areas (countries) that is compatible with operational security standards.

Transmission Reliability Margin (TRM) is the part of the TTC set aside for security to cope uncertainties arising from: (1) inadvertent deviations of physical flows between control areas; (2) Emergency exchanges between TSOs to address unbalanced situations in real-time; (3) Inaccuracies in data collection and measurements.

Unbundling is the separation of the operation (and sometimes ownership) of transmission assets and generation assets.

Voltage and reactive power control maintains an acceptable voltage profile throughout the network. This is achieved through the balancing of the respective reactive power requirements of the network and the customers.

Wholesale Market is the business involving transactions among re-sellers, participants that do not actual use the product traded, but re-sell it to others, either other wholesalers or to end users. This includes transactions where the purchaser typically re-sells the power to an end user or another participant that then re-sells the power.

Appendix I -- Transparency

The Guidelines describe the importance of transparency as a component of successful market integration, something that is emphasized in the EU reforms. Transparency is accomplished by publishing relevant data that eliminates information asymmetries and provides all market participants critical market information. The main transparency requirements have been promulgated in Annex 1 to Regulation (EC) No 714/2009. The transparency requirements in the Annex are listed below:

GUIDELINES ON THE MANAGEMENT AND ALLOCATION OF AVAILABLE TRANSFER CAPACITY OF INTERCONNECTIONS BETWEEN NATIONAL SYSTEMS,

ANNEX I

TRANSPARENCY

5.1. TSOs shall publish all relevant data related to network availability, network access, and network use, including a report on where and why congestion exists, the methods applied for managing the congestion and the plans for its future management.

5.2 TSOs shall publish a general description of the congestion management method applied under different circumstances for maximising the capacity available to the market, and a general scheme for the calculation of the interconnection capacity for the different timeframes, based upon the electrical and physical realities of the network. Such a scheme shall be subject to review by the Regulatory Authorities of the Member States concerned.

5.3 The congestion management and capacity allocation procedures in use, together with the times and procedures for applying for capacity, a description of the products offered and the obligations and rights of both the TSOs and the party obtaining the capacity, including the liabilities that accrue upon failure to honour obligations, shall be described in detail and made transparently available to all potential network users by TSOs.

5.4 The operational and planning security standards shall form an integral part of the information that TSOs publish in an open and public document. This document shall also be subject to review of national Regulatory Authorities.

5.5 TSOs shall publish all relevant data concerning cross-border trade on the basis of the best possible forecast. In order to fulfil this obligation the market participants concerned shall provide the TSOs with the relevant data. The way in which such information is published shall be subject to review by Regulatory Authorities. TSOs shall publish at least:

(a) annually: information on the long-term evolution of the transmission infrastructure and its impact on cross-border transmission capacity;

(b) monthly: month- and year-ahead forecasts of the transmission capacity available to the market, taking into account all relevant information available to the TSO at the time of the forecast calculation (e.g. impact of summer and winter seasons on the capacity of lines, maintenance on the grid, availability of production units, etc.);

(c) weekly: week-ahead forecasts of the transmission capacity available to the market, taking into account all relevant information available to the TSOs at the time of calculation of the forecast, such as the weather forecast, planned maintenance works of the grid, availability of production units, etc.;

(d) daily: day-ahead and intra-day transmission capacity available to the market for each market time unit, taking into account all netted day-ahead nominations, day-ahead production schedules, demand forecasts and planned maintenance works of the grid;

(e) total capacity already allocated, by market time unit, and all relevant conditions under which this capacity may be used (e.g. auction clearing price, obligations on how to use the capacity, etc.), so as to identify any remaining capacity;

(f) allocated capacity as soon as possible after each allocation, as well as an indication of prices paid;

(g) total capacity used, by market time unit, immediately after nomination;

(h) as closely as possible to real time: aggregated realised commercial and physical flows, by market time unit, including a description of the effects of any corrective actions taken by the TSOs (such as curtailment) for solving network or system problems;

(i) ex-ante information on planned outages and ex-post information for the previous day on planned and unplanned outages of generation units larger than 100 MW.

5.6 All relevant information shall be available for the market in due time for the negotiation of all transactions (such as the time of negotiation of annual supply contracts for industrial customers or the time when bids have to be sent into organised markets).

5.7 The TSO shall publish the relevant information on forecast demand and on generation according to the timeframes referred to in 5.5. and 5.6. The TSO shall also publish the relevant information necessary for the cross-border balancing market.

5.8 When forecasts are published, the ex post realised values for the forecast information shall also be published in the time period following that to which the forecast applies or at the latest on the following day (D+1).

5.9 All information published by the TSOs shall be made freely available in an easily accessible form. All data shall also be accessible through adequate and standardized means of information exchange, to be defined in close cooperation with market parties. The data shall include information on past time periods with a minimum of two years, so that new market entrants may also have access to such data.

5.10 TSOs shall exchange regularly a set of sufficiently accurate network and load flow data in order to enable load flow calculations for each TSO in their relevant area. The same set of data shall be made available to the Regulatory Authorities and to the European Commission upon request. The Regulatory Authorities and the European Commission shall ensure the confidential treatment of this set of data, by themselves and by any consultant carrying out analytical work for them on the basis of these data.

Appendix II -- Balancing and Ancillary Services

This appendix is in three parts: (1) Definitions of balancing and ancillary services; (2) Example of cost-of-service ratemaking for balancing and ancillary services; and (3) Approach taken on ancillary services pricing by Hungary during its market liberalization process.

1. Definitions

As the Guidelines describe, a key step in developing balancing and ancillary services markets is to harmonize the definitions of the products used so that eventually they may be traded on a standardized basis. The standardized definitions used in the Network Codes should be the basis of this effort. Regulators should adopt common positions on balancing and ancillary services definitions. The main definitions used in the Network Codes for balancing and ancillary services are reflected in the list below.

Balancing is the actions and processes through which TSOs ensure that total electricity withdrawals are equaled by total injections in a continuous way, in order to maintain the system frequency within a defined stability range.

Balancing Energy is the actual use of this capacity which may come from the set aside of reserves that the TSO may procure from market participants or neighboring systems.

Balancing Reserves *(or* ***Balancing Capacity*** *or* ***Reserve Capacity****)* is the idle capacity the TSO keeps on hand to meet unexpected imbalances.

Balance Responsible Party is the market-related entity or its chosen representative responsible for its imbalances.

Balancing Service Provider is a market participant providing Balancing Services to its TSO.

Balancing Services is either or both Balancing Capacity and Balancing Energy.

Imbalance is an energy volume calculated for a Balance Responsible Party and representing the difference between the Allocated Volume attributed to that Balance Responsible Party, and the final Position of that Balance Responsible Party and any Imbalance Adjustment applied to that Balance Responsible Party, within a given Imbalance Settlement Period.

Frequency Containment Reserves (Primary Reserves) are operating reserves necessary for constant containment of frequency deviations (fluctuations) from nominal value to constantly maintain the power balance in the whole synchronously interconnected system. These are deployed using Automatic Generation Control (AGC) within 30 seconds to regulate the frequency on a moment-to-moment basis. This category typically includes operating reserves with the activation time up to 30 seconds. Operating reserves of this category are usually activated automatically and locally.

Frequency Restoration Reserves (Secondary Reserves) are operating reserves necessary to restore frequency to the nominal value after sudden system disturbance occurrence and consequently replace frequency containment reserves (FCR) if the frequency deviation lasts longer than 30 seconds. These are deployed both automatically and manually within between 30 seconds and 15 minutes when an imbalance arises to replace used up Primary reserves.

Replacement Reserves (Tertiary Reserves) are operating reserves necessary to restore the required level of operating reserves in the categories of FCR and frequency restoration reserves (FRR) due to their earlier usage. These are deployed manually between 15 minutes and longer time frames to replace secondary reserves.

Ancillary services can comprise several other products depending on the market. In addition to the balancing services, other ancillary services products may include:

Voltage and Reactive Power Control maintain an acceptable voltage profile throughout the network. This is achieved by balancing of the respective reactive power requirements of the network and the customers.

Black Start Capability is the ability of a generating unit to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

Islanding Capability is the ability to supply a grid area in isolation of the synchronous grid over extended periods of time, autonomously and with the aid of a generating unit, in order to maintain operation within the permitted operating parameters.

2. Example of Cost-Based Ancillary Services

The following is a summary of the steps in establishing cost-based ancillary services for reserve capacity. This discussion is taken from "Ancillary-Services Costs for 12 US. Electric Utilities," by Brendan Kirby and Eric Hirst, Oakridge National Laboratory, April 1996. It addresses the approach taken by the U.S. Federal Energy Regulatory Commission in establishing cost-based rates for ancillary services. The example is for "load-following" ancillary services, which is an ancillary service that responds automatically to imbalances. It is analogous to the automated Primary and Secondary Reserves in the EU. This discussion can also apply to non-automatic reserve products by removing the cost of equipment that allows an automated response.

Example of an embedded-cost method used to calculate ancillary-service costs: load following

1. Determine the amount of generating capacity (MW) required to provide this service and whether the required amount varies with time (by hour, day of the week, or season).

2. Identify the generating-station capital equipment (generating units, governors, automatic generation control equipment, computers, and so on) that provide this load following service. Determine how much capacity (up and down) each unit provides.

3. Calculate the annualized capital cost for the equipment identified in step 2. (These numbers are based on the fraction of each piece of equipment assigned to [automated response] and on the depreciated values of each piece of equipment multiplied by the [depreciation rate and the cost-of capital])[22]

4. Determine the fixed operations, maintenance, and labor costs for the equipment identified in step 2.

5. Calculate the incremental operating costs (fuel associated with heat-rate degradation from constant cycling, the costs of out-of-merit-order dispatch, plus additional maintenance to compensate for the wear and tear on the units caused by cycling) for the generating units identified in step 2 because of the

[22] See Section 2.3.4 for how to calculate depreciation and cost-of-capital.

unit's operation to provide load following. Determine the incremental operating costs, if any, of other equipment used to provide this service.

6. Compute the annualized control-center costs for load following (automatic generation control, computers, and other equipment) plus annual labor costs assigned to load following.

7. Sum the costs from steps 3, 4, 5, and 6.

8. Divide the amount from step 7 by the amount of generating capacity from step 2. The result, in $kW-year, is the annual cost of load following.

3. Procurement and Market Development of Ancillary Services in Hungary since the beginning of Market Liberalization (2003-2016)

Background

Between 1996 and 2009, the European Union (EU) adopted three consecutive legislative packages to liberalize and harmonize different national and largely-isolated electricity markets to advance implementation the European Union Internal Energy Market. The main objective of the reform has been to promote efficiency and competition at each possible level of the value chain. Changes included the introduction of regulated third-party access to electricity networks, the unbundling of transmission and distribution systems, the opening of wholesale and retail markets for competition, and the formation of comprehensive trading arrangements.

After Hungary's membership application to the EU was approved, a hybrid electricity market model was implemented on 1 January 2003. In the hybrid model, the free market and the public utility market segments operated side by side. The hybrid model was designed to gradually introduce an open market and initially allow supply choice to only larger industrial customers. The hybrid market model was replaced by a fully competitive market model in 2008, empowering small retail customers to purchase electricity directly from generators or traders. In this model, competition can only be restricted to prevent abuse of market power.

In the course of liberalization, wholesale and retail markets were created to encourage competition in generation and trading, while transmission and distribution remained regulated natural monopolies with open access rules to the networks. Transactions, formerly concluded within the state-owned vertically integrated Hungarian Electricity Company (MVM), had been gradually replaced by free market transactions on the wholesale and retail markets. In addition, a specific market for ancillary services was created. The necessity of proper and sufficient ancillary services, including different balancing reserves, system services and capabilities, is the key element to keeping the electricity system in balance. The original goal of introducing market-based procurement and pricing of ancillary services was to guarantee their availability at the lowest possible cost in a transparent and competitive manner.

2003 – 2007

Long before market liberalization started, ancillary services were demanded and provided within the same company (MVM). Thus, to arrange their procurement was not complicated. The vertically integrated company's own assets were used to deliver the different services. However, state-owned generation was reorganized into eight different generating companies and privatized in 1995. With the exception of the nuclear power plant and a medium-sized coal-fired power plant, foreign strategic investors acquired all generation facilities. To support the privatization process, MVM and the strategic investors concluded 20-25 year, long-term contracts and power purchase agreements (PPA). Most of domestic generation capacities were reserved through these contracts, so MVM remained the dominant market participant and almost the only potential supplier of ancillary services.

In 2000, an independent system operator (MAVIR) was established as part of the electricity market reform process.23 MAVIR was obliged to purchase electricity and obtain power plant generation capacity to the extent necessary to ensure ancillary services. The procurement process had to be transparent, either through a public procurement process accessible to any resident or non-resident producer or trader, or from the organized electricity market24.

MAVIR implemented the first transparent and non-discriminatory procurement tenders in 2003. However, MVM was almost the only market participant being eligible to participate at these tenders. Since the first step to organize a truly competitive ancillary services procurement system mostly failed, MAVIR tried to purchase these services on a daily and hourly basis. Until 2007, MAVIR held auctions at regular intervals (once or twice annually, daily or hourly). Each participant offered bids — including a capacity fee and an energy fee — for both upward and downward regulation. The settlement was based on the offered price: the so-called pay-as-you-bid model. Only selected, or contracted, bidders received the capacity fee for their availability, and in case of activation, MAVIR also paid an energy fee for those market participants providing upward or downward regulation. It should be noted that the activation was based on merit order to ensure the cost minimization.

MAVIR procured the following types of ancillary services:

- As a first step toward operational stability, primary control reserves stabilize system frequency of the given power system;
- Secondary control reserves to modify the active power set points by adjustment of controllable generation (only upward direction; the maximum capacity fee regarding the downward direction was 0 HUF/MW/h);
- Minute control reserves to supplement the activated secondary control reserves (only upward direction, the maximum capacity fee regarding the downward direction was 0 HUF/MW/h);
- Hourly control reserves to supplement the activated minute and/or secondary control reserves (only upward direction, the maximum capacity fee regarding the downward direction was 0 HUF/MW/h).

It is also important to mention that during this period there was no need to contract reserve for downward regulation, because most of the power plants operated close to their possible maximum level (technical maximum), so the capacity was ensured for activation by their operational characteristics. The simple reason behind the almost constant availability of downward reserve capacity was the high wholesale electricity price and lower marginal costs.

The most important barrier to competition on the ancillary services market was the PPA system that resulted in significant market dominance by MVM. MAVIR covered the costs of its procurement of different services, almost exclusively from MVM. To reduce the cost of ancillary services and to enhance market liquidity, the Hungarian Energy Office (HEO) obliged MVM to submit bids to the ancillary services

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[23] MAVIR was established as an ISO in 2000, then re-integrated into MVM in 2006 (legal unbundling status) and was approved as an Independent Transmission Operator (ITO) in 2012.

[24] Note that the Hungarian power exchange was established by MAVIR only in 2007.

market so that the bid price did not exceed the settlement price of a given contract with a specific generator.

The type, amount and cost of available generation reserves were also influenced by arrangements connected to the integration of the Hungarian electricity system into the European integrated electricity system. After the 1990 political changes, Hungary applied for UCPTE25 membership. At the early stage of the negotiations it was concluded that the Hungarian electricity system did not have the sufficient reserves to be activated in case of forced outages. In accordance with the regulations of UCPTE, systems could participate in the union of co-operating systems only if they were able to fulfil the requirements of its Operation Handbook (OH). According to the OH, each member of the union is obliged to have enough reserve available to cover the loss of the largest unit in their system. It meant that the Hungarian electricity system should have had at least the same amount of reserve capacity as one unit of the Nuclear Power Plant of Paks (500 MW). For this reason, MVM installed three open cycle gas turbine units (approx. 430 MW aggregate installed capacity) financed by the World Bank and EIB. These turbines were the so-called contingency reserves, the capacity from which was not subject of the procurement of ancillary services. To ensure system security and at the same time to guarantee the repayment of the loans needed to install the gas turbines, MVM and MAVIR entered into a long-term contract that stipulated that the capacity was available exclusively for MAVIR, which contracted them on a fixed-capacity fee adjusted annually for inflation. The pricing of these contingency reserves was based on the long term agreement, which was a typical cost-plus-fee contract in case of both capacity fee and control energy fee.

2008 – Present

On 21 May 2007, a large-scale system security incident took place in Hungary. Two major power plants had forced outages and reserves were not enough to cover the loss. In response to the event, MAVIR restricted customer load for nearly one hour to stabilize the system. After an investigation of unexpected failures, the HEO penalized and obliged MAVIR to introduce a market-maker scheme in the procurement of ancillary services. The aim of the market-maker scheme was to guarantee the liquidity of bids on a daily basis to ensure the availability of reserves by contracting them. On each tendering procedure (yearly, quarterly or weekly), a certain amount of reserve capacity is procured. As a result of each procurement, the selected Balancing Service Providers (BSPs) offering the best bids concluded a market-maker contract for the given period. Others receive optional contracts. In a market-maker contract, the parties assume reciprocal obligations. BSPs submit bids that meet the terms and conditions defined in the contract (power, amount, maximum values of availability fee, and energy fee, etc.). The TSO accepts such bids in accordance with the rules of the market-maker contract. In an optional contract, the TSO can contract the submitted reserves, but there is no obligation to do so.

After Hungary's accession to the EU in 2004, the European Commission (EC) started to scrutinize the compatibility of the PPAs with European Union Law on State Aid. In 2008, the EC decided that some critical components of the PPAs, between MVM and power plants owned by strategic investors, constituted illegal state aid under EU law. In response to the EC's decision, the Hungarian legislation terminated the PPAs by the end of 2008. With the termination of PPAs, the most important barrier to further market development had been overcome.

The economic recession after the 2008-09 financial crisis and the significant increase in the deployment of government-supported renewable generation resulted in sharply decreasing wholesale electricity

[25] Since 1998 UCTE, Union for the Coordination of the Transmission of Electricity, since 2008 ENTSO-E, European Network of Transmission System Operators for Electricity.

prices in continental Europe. These developments also affected the operational environment of the Hungarian power plants and led to a very low average annual utilization level for BSPs. The low utilization rate (often just around 10percent) meant that the availability for downward regulation had no longer been guaranteed without any further incentive. Partly in response to the above developments, several important changes were introduced in the Hungarian ancillary services market between 2009 and 2012:

- The five types of ancillary services mentioned before (primary, secondary, minute, hourly, contingency reserves) were reduced to three by creating the tertiary control merged from minute, hourly, and contingency reserves.
- The sequence of procuring the different services has a significant effect on tender results due to the relative scarcity in bids. Today, secondary control is procured first, followed by tertiary control.
- Each ancillary service has an upward and a downward direction, which are procured independently, there is no "symmetric" bidding obligation, except for primary control services.
- Several modifications were made to the tendering rules and procedures to generate more efficient competition among the market participants and to decrease the procurement (reservation) and activation costs.
    - The bidding scheme was modified from a single-round bidding to a two-round bidding scheme in 2010, which enabled service providers first to bid their services and then modify (decrease or keep) the price elements of their bids. Since 2012, a pure price-based auction was introduced with multi-round e-auction bidding to enable the service providers to compete with one another.
    - The share of shorter-term ancillary services procurement increased. Instead of annual auctions, MAVIR has been implementing quarterly and weekly auctions since 2012.

Price control mechanisms

While Hungary introduced a quasi-competitive pay-as-you-bid procurement system for ancillary services from the beginning of electricity market opening, this system has been complemented with different price controls, including price caps. Price caps were applied to the maximum capacity fee, in present time for upward (60,000 Ft/MWh, for downward 80,000 Ft/MWh) and energy fee (in present time for upward 100,000 Ft/MWh, for downward 35,000 Ft/MWh) in the market-maker contract. Since the end of 2014, the price cap for the downward regulation energy fee was increased from 0 Ft/kWh to 35 Ft/kWh (cc 11 €c/kWh) to encourage potential service providers to enter the market under a depressed wholesale electricity price environment.

Until the end of 2008, when the long-term PPAs between MVM and the generation companies were terminated by legislation, the primarily cost-based pricing rules of the PPAs had to be applied by the dominant market participant MVM in its bids to the ancillary markets.

Regarding the imbalance settlement between 2008 and 2012, price floors were applied to incentivize BRPs to keep in balance. The cost of activated control energy and the wholesale electricity price provided the basis of imbalance settlement. The imbalance settlement price was always higher than the above mentioned prices for upward direction. During this period the price cap for the downward regulation control energy fee was maximum 0 HUF/kWh (as it was noted above) so the imbalance settlement price was also 0 Ft/kWh.

Appendix III -- Market Monitoring

The Guidelines explain how market power is a significant challenge in the transition to competitive markets. If one or more participants have market power and can control prices, relying on markets to supply electricity may not be effective. Market power can be addressed by effective market monitoring and market power mitigation. As discussed in the Guidelines, when competition is in place, Black Sea regulators should use their authority to "prevent" market manipulation through mitigation measures. Such mitigation could include offer caps for suppliers with market power, thereby preventing the exercise of market power. This type of market power mitigation is common in the US and has been effective. The first subsection in the Appendix explains the regulator's role in market monitoring as provided by Regulation (EC) 1227 and explains the regulator's authority to monitor and mitigate market power.

The second subsection below discusses how regulators can measure whether a market is ready for competition. The Guidelines explain why it is important for regulators to monitor the structure of the market and to measure when market power may be present. The analysis shows how market shares can be calculated to determine when the market is likely to be competitive.

1. Market Monitoring and Market Power Mitigation Authority under Second and Third Package

Monitoring Cross-Border Capacity Calculation. Regulation (EC) No. 713/2009 (part of the Third Package) provides the most direct guidance on monitoring electricity markets. Article 11 of the Regulation is titled "Monitoring and reporting on the electricity and natural gas sectors":

> [ACER], in close cooperation with the Commission, the Member States and the relevant national authorities including the national regulatory authorities…shall monitor the internal markets in electricity and natural gas, in particular the retail prices of electricity and natural gas, access to the network including access of electricity produced from renewable energy sources, and compliance with the consumer rights…

As the quoted portion of the Regulation states, market monitoring envisions access to the grid as a distinct area of monitoring. It is well recognized in EU reforms (as well as in the general opinion regarding market liberalization) that non-discriminatory access to the grid is a critical factor in successfully liberalization.[26]

Regulation (EC) No. 714/2009. While Article 11 of regulation 713 contemplates monitoring access to the grid, regulation 714 (network access and congestion management) also envisions close involvement of regulators in the process of estimating and allocating cross-border capacity.

In addition, Regulation 714 (Article 16(3)) states:

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[26] See, for example, Regulation 714 at page L 211/16:

> The precondition for effective competition in the internal market in electricity is non-discriminatory and transparent charges for network use including interconnecting lines in the transmission system. The available capacity of those lines should be set at the maximum levels consistent with the safety standards of secure network operation.

> The maximum capacity of the interconnections and/or the transmission networks affecting cross-border flows shall be made available to market participants, complying with safety standards of secure network operation.

Article 19 in the same Regulation charges the Regulatory Authorities to ensure compliance:

> The regulatory authorities, when carrying out their responsibilities, shall ensure compliance with this Regulation and the Guidelines adopted pursuant to Article 18. Where appropriate to fulfil the aims of this Regulation the regulatory authorities shall cooperate with each other, with the Commission and the Agency in compliance with Chapter IX of Directive 2009/72/EC.

The cited Chapter IX of Directive 2009/72 explicitly sets the following objectives and duties for the regulatory authorities:

> Article 36 (c) eliminating restrictions on trade in electricity between Member States, including developing appropriate cross-border transmission capacities to meet demand and enhancing the integration of national markets which may facilitate electricity flows across the Community;
>
> Article 37 (b) ensuring compliance of transmission and distribution system operators and, where relevant, system owners, as well as of any electricity undertakings, with their obligations under this Directive and other relevant Community legislation, including as regards cross-border issues;
>
> Therefore, Regulation 713 specifically sets access to the grid as key area of market monitoring. Regulation 714 specifically requires that the maximum capacity be made available and that TSO compliance with this maximum availability is a duty and objective of the regulatory authorities.

Monitoring Participant Conduct. Regulation (EC) 1227 provides explicitly for market monitoring for market manipulation in wholesale electricity markets. In article 7 of Regulation 1227, market monitoring is addressed:

1. [ACER] shall monitor trading activity in wholesale energy products to detect and prevent trading based on inside information and market manipulation. It shall collect the data for assessing and monitoring wholesale energy markets as provided for in Article 8.

2. National regulatory authorities shall cooperate at a regional level and with the Agency in carrying out the monitoring of wholesale energy markets referred to [above].

2. Market Shares and Workable Competition

(Based on the presentation of Dr. Hisham Choueiki given at the June 2016 BSRI Workshop, Bucharest, Romania)

In the US, the Federal Energy Regulatory Commission (FERC) grants a supplier the right to electricity products at market-based rates if the supplier can verify that it does not have vertical or horizontal market power.

Vertical market power may be verified by having the suppliers be divested from transmission assets (unbundled) or if it owns transmission assets that it has filed an open access transmission tariff at FERC or by joining a multilateral energy market under an Regional Transmission Organization, e.g., Midcontinent ISO, New York ISO, PJM ISO. In the EU, this is not a problem because the transmission system is operated by an independent TSO.

Horizontal market power may be verified by passing the market share screen and the pivotal supplier screen. The pivotal supplier screen is conducted within a relevant geographic market. FERC defines the relevant geographic market to be the local balancing authority service area. In the Black Sea Region, the individual countries would stand as the geographic markets. In its analysis, FERC defines the relevant product to be the supplier's uncommitted nameplate or seasonal capacity in the relevant market.

The supplier's uncommitted capacity is equal to: Nameplate (or seasonal) capacity plus long-term firm purchases minus long-term firm sales minus operating reserves minus planned outages (for the market share screen only). In other words, if a supplier has part of its capacity committed under a long-term contract or other obligation, it cannot sell that committed capacity in the market. Therefore, FERC is attempting to measure who has the *uncommitted* capacity to sell into a market.

Market Share Screen

The market share of the market participant (MP) during a particular season is computed as the ratio of the MP's uncommitted capacity to the total uncommitted capacity in the relevant product market.

The supplier will pass the FERC's market share screen if its market share is less than 20 percent in all four seasons. The following is an example of a market participant that fails the market share test. It shows that the MP's uncommitted capacity is over 11,000 MW in the four seasons analyzed. The other MPs have over 30,000 MW together in these seasons. The share of the individual market participant is over 25 percent in all four seasons, thus failing the market share test in this example.

What IF Market Share Screen

			Season					
No	**Category**	**%**	**Summer**	**Fall**	**Winter**	**Spring**	**Calculation**	**Comments**
	Calculations of the MP							
1	Nameplate Capacity	100%	12,514	12,514	12,514	12,514		From the Pivotal Supplier Test
2	Long Term Firm Purchases	100%	0	0	0	0		From the Pivotal Supplier Test
3	Imports	100%	0	0	0	0		
4	**Native Load Committed**	100%	**0**	**0**	**0**	**0**		**SET to 0**
5	**Operating Reserve**	100%	**0**	**0**	**0**	**0**		**SET to 0**
6	Planned Outages	100%	17	576	261	952		
7	Long Term Firm Sales	100%	0	0	0	0		From the Pivotal Supplier Test
8	**MP Uncommitted Capacity**		**12,497**	**11,938**	**12,253**	**11,562**	**1+2+3-4-5-6-7**	
	Calculations of all other MP							
9	Nameplate Capacity	100%	135,752	135,752	135,752	135,752		From the Pivotal Supplier Test
10	Long Term Firm Purchases	100%	0	0	0	0		From the Pivotal Supplier Test
11	Imports	100%	0	0	0	0		
12	Native Load Committed	100%	72,728	58,667	63,294	56,997		
13	Operating Reserve	100%	2,734	2,593	2,639	2,576		
14	Planned Outages	100%	978	6,234	3,258	6,217		
15	Long Term Firm Sales	100%	0	0	0	0		From the Pivotal Supplier Test
16	**∑Other Uncommitted Capacity**	**49%**	**29,063**	**33,446**	**32,615**	**34,281**	**9+10+11-12-13-14-15**	**ASSUME 49% Deliverability**
17	**Total Uncommitted Capacity**		**41,560**	**45,384**	**44,868**	**45,843**	**8+16**	**∑All Uncommitted Capacity**
18	**MP Share**		**30.1%**	**26.3%**	**27.3%**	**25.2%**	**8/17**	**MP Uncommitted / ∑(All Uncommitted)**
19	**Market Share Test-Pass/Fail**		**FAIL**	**FAIL**	**FAIL**	**FAIL**	**<20%**	

Pivotal Supplier Screen

Whether or not a supplier is pivotal in the relevant market is assessed at the time the local balancing authority hits its annual peak demand. A supplier will pass the pivotal supplier screen if the "wholesale load proxy" in the relevant market can be met without any megawatts being provided from the uncommitted capacity of that supplier.

Pivotal Supplier Screen

No	Category	Effect	MW	Calculation	Comments
	Calculations of the MP				
1	Nameplate Capacity	+	12,514		
2	Long Term Firm Purchases	+	0		
3	Imports	+	0		
4	Native Load Committed	-	8,037		
5	Operating Reserve	-	**298**		
6	Long Term Sales	-	0		
7	**MP Uncommitted Capacity**		**4,179**	**1+2+3-4-5-6**	
	Calculations of all other MP				
8	Nameplate Capacity	+	135,752		
9	Long Term Firm Purchases	+	0		
10	Imports	+	0		
11	Native Load Committed	-	76,893		
12	Operating Reserve	-	**2,775**		Difference of Area Reserve Req - MP Reserve
13	Long Term Sales	-	0		
14	**∑Other Uncommitted Capacity**		**56,084**	**8+9+10-11-12-13**	
15	**Total Uncommitted Capacity**		**60,263**	**7+14**	
16	Annual Peak Load		104,497		
17	**Native Load Proxy**		**84,930**	**4+11**	**All of the Native Load Committed**
18	**Wholesale Load Proxy**		**19,567**	**16-17**	**Annual Peak Load - Native Load Proxy**
19	**Net Uncommitted Supply**		**40,696**	**15-18**	**∑All Uncommitted Capacity - Wholesale Proxy**
20	**Difference NET-MP**		**36,517**	**19-7**	**Net Uncommitted Capacity - MP Uncommitted Supply**
21	**Pivotal Supplier Test-YES to Pass**		**PASS**	**7<19?**	**MP Uncommitted Capacity<Net Uncommitted Supply**

The calculation in this chart determines if the capacity (MW) controlled by this market participant is needed to meet the market wholesale demand ("Wholesale Load Proxy). The first six lines show that the MP has more than 4,000 MW of uncommitted capacity. Total uncommitted capacity (line 15) is slightly more than 60,000 MW. The annual peak load is 104,000 MW. Line 17 indicates that 84,930 MW of the annual peak load is covered by existing native load obligations. This leaves 19,567 MW that is served by the wholesale market. The total capacity that is not committed to native load is 40,696 (line 19). This means that there is over 60,000 MW to serve less than 20,000 MW of wholesale load. This is an over-supplied market so market power is not that likely. Indeed, since the MP being tested only has 4,179 MW of uncommitted resources, the wholesale market can clearly be satisfied by the other suppliers' uncommitted capacity without the uncommitted capacity of the individual market participant. This means the MP is not pivotal.

Appendix IV -- Renewable Integration

The Guidelines explain that renewable energy resources integration is a critical competent of the EU energy market reforms. EU reforms have made integration of renewable resources a priority in Directive 2009/28/EC, which established binding renewable targets for all Member States. Hence, renewable integration is a key component of market reform.

In this appendix, we present principles of renewable integration that were developed in previous engagements for the Black Sea regulators.[27] These principles inform the next steps as discussed in the Guidelines. The following listing comprises principles that are useful as a resource as reform goes forward. They are not formulated as next steps in this current process. The next steps for renewable integration are discussed above in section 2.4.1. and rely on these principles. As the market reforms advance, these principles will help inform future next steps as well.

The following principles are excerpted from Dr. Kaderjak's paper.[28]

Section 6 - Grid access and integration

(1) The penetration of RES generation technologies is hindered by technical and economic challenges that inhibit their integration into the electricity network. These challenges can be discussed under the following headings:

a. Distance from resource to load: large scale and high quality renewable resources, such as off-shore wind or solar power in the desert, are usually far away from the load centers.

b. Obsolete grid infrastructure: insufficient transport capacity, network design and limited interconnections due to outdated systems may often block or delay renewable development.

c. Scarcity of high-quality RES resources and grid connection capacity: there might be multiple applications to develop the same RES resource or use the same grid connection possibilities.

d. Intermittency: weather-dependent renewable generation is not only unable to follow any pre-set schedule, but in many cases even 12-hour production forecast errors are an order of magnitude larger than those for demand predictions.

e. System flexibility: as variable production sources are introduced into the grid at a larger scale, the flexibility of the system must also be expanded to avoid adversely affecting the security of electricity supply and the integrity of the grid.[29]

(2) The penetration of RES generation is often constrained by network expansion and upgrade opportunities. The time required to permit and install RES generation units is often significantly shorter than that for network expansion and upgrades necessitated by massive new RES connections. It is also common that regulators first put effective incentives in place (e.g. in the form of generous feed in tariff systems) to encourage new RES generation, but neglect similarly effective remuneration schemes for transmission and distribution companies for their grid development efforts.

27 Kaderjak, Peter, "Principles of Regulation to Promote the Development of Renewable Energy in the Black Sea, April 2012, (supported by USAID and NARUC).

28 Id.

29 A key issue that was explained at the June 2016 workshop was the experience in Turkey where renewable integration expanded the need to address imbalances in the real-time market.

(3) Therefore, an important RES related regulatory task is to develop an effective incentive regulation to remunerate RES related network investments. Such regulation should include a method to define and allocate connection and network upgrade costs among RES producers, network companies, and final customers.

Definition and allocation of connection and upgrade costs

(4) The two major types of costs related to RES utilization are the cost of developing the resource (e.g. installation of a wind farm or developing a hydro generation unit) and the cost of its connection to the distribution or transmission grid. While the cost of developing the resource should clearly be covered by the investor,[30] the definition and allocation of the cost of connection between the developer and the network company is often a matter of policy or regulatory choice.

(5) The total cost of connection consists of the direct cost of connection to a network substation and the potential additional costs of network upgrade and/or expansion that the new connection might make necessary. When developers only pay for the direct cost of connection to a substation, it is a super shallow connection charge regime. When developers have to pay for the direct cost of connection and also for the necessary upgrade of the existing grid, it is a shallow connection charge regime. Finally, when developers have to pay for the total cost of connection, it is a deep connection charge regime.

(6) Economic theory suggests that the deep connection charge regime is the proper choice for connection cost allocation. According to the cost-causality principle, costs should be borne by those who cause them.[31]

(7) Based on this principle, European regulators propose that charges for connecting to and using the system should, in principle, be transparent, cost-reflective and not dependent on the source of the electricity.[32] Such a regulation will encourage developers to carefully evaluate the trade-offs between RES quality and the cost of connection.

(8) In the US, more effort is put into identifying both the costs and benefits of grid expansion and to develop cost allocation regulation based on the results of cost-benefit analyses.

(9) Regulators can also decide to partly or fully socialize the cost of connection and grid upgrade, to facilitate the satisfaction of RES policy objectives. Socialization in this context means that retail customers, instead of developers, pay, in the form of network or end customer tariff increases, part or the full cost of network expansion to integrate RES into the grid.

(10) Under a fully regulated, vertically integrated market structure, the total cost of connection is paid by end-use customers.

(11) When independent RES generators are allowed to enter the market, the Regulator might consider partial or full connection cost socialization to ensure that transmission lines are built and RES generators locate where the best resources exist. Large-scale and high quality renewable resources, such as off-shore wind or solar power in the desert, are usually far away from the load centers. Providing access by extending transmission lines close to these resources can be, with good reason, considered public investments to benefit from positive network externalities.

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[30] (original footnote 3) Publicly provided investment grants often contribute to investment costs. Tax credits are also applied to promote RES investments.

[31] Many EU countries do not adopt the direct allocation and instead, to advance social policy, regulators spread the cost across all electricity users.

[32] (original footnote 4) Regulatory aspects of the integration of wind generation in European electricity markets. A CEER Conclusions Paper, Ref: C10-SDE-16-03. 7 July 2010, pp. 20-22.

(12) Cost socialization of grid expansion or upgrade (e.g. the promotion of net metering) might also help the spread of small, decentralized RES generators and household micro-generation which could otherwise be prohibited by network connection costs being high relative to the size of these projects. However, connection cost socialization in the case of RES will distort the competition across generation projects of different fuel sources.

(13) The regulatory practice with regard to connection cost allocation is diverse both in the US and the EU. The Federal Energy Regulatory Commission of the US has not adopted a generally applicable standard or method for transmission cost allocation, so in the US, the method used for allocating the costs of new transmission facilities varies across the transmission system operators. In the EU, the National Regulatory Authorities regulate connection cost allocation.

(14) Integrated generation and transmission planning might help transmission operators and regulators to better understand the trade-offs between renewable resource quality and the cost of connection and to design a sufficient connection charge system.

(15) When RES investors are to connect to integrated network operators that have production and trading interests, these operators might be motivated to foreclose those RES projects from the market that compete directly with their production units. These barriers can be easily implemented by the integrated network operator through discriminatory practices to grid connection requests. To promote fair competition for development opportunities, regulators should ensure transparent and nondiscriminatory practices from the side of network companies with regard to grid connection and access.

(16) Technical standards for the connection of RES producers should be established by grid operators and approved by the regulator, e.g., as part of the network company's Grid Code. Such technical standards should be transparent, easily available for investors, and should strike the right balance between system reliability needs and simplicity to promote RES penetration.

Queue management

(17) The volume and asymmetry of incentives and development time requirement between RES generation and network upgrade projects (referred to [above]) often results in competing investor requests (or queues) to develop certain renewable resources or to connect production facilities at given grid connection points.

(18) 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.

(19) Providing non-constrained connection rights for RES developers might lead, under market and regulatory conditions favorable for these developers, to a very fast and excessive RES penetration that might compromise grid 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 industry, but might turn out to be unsustainable in the long run.

(20) A more promising regulatory approach to managing competing investor requests is queue management. This will include the establishment of connection capacity limits and the development of rules of connection capacity allocation.

(21) Regulation of queue management should be ready and published before the resource is opened for developers.

(22) Competitive tendering to allocate connection capacity and/or resource development licenses (or rights) should be preferred to other allocation schemes (e.g. first come first served) because such tenders might provide RES resource development at least cost for the customers. For example, winning a tender of this sort can be based on the fee/kWh feed in tariff bid of the developers. Such a scheme, by promoting competition, might provide a significant discount to an officially established uniform feed in tariff.

(23) In case of connection capacity licenses (rights), the TSO is best positioned to manage competitive tendering. Resource development rights can also be managed by the regulator, in cooperation with the network company.

Intermittency and balancing

(24) Weather-dependent (or intermittent) renewable energy generation technologies – such as wind and solar power – are to some extent inherently uncontrollable. Therefore, once they are connected to the grid, they are unable to operate as load-following entities. Moreover, their production levels cannot be predicted with absolute certainty even a few hours ahead of real time. Since low-cost, flexible technological options for providing largescale storage of electric power are not yet available, the massive application of intermittent RES poses a challenge to the continuous real-time system balancing operations of the affected grid company.

(25) To ease the stress on system balancing, the regulator should establish incentives both for intermittent RES producers to provide improved forecasts of their future production to the system operator and for the system operator to allow those producers more flexibility in adjusting their forecasts as better weather forecast information becomes available for them.

(26) A sufficient incentive for intermittent RES producers to improve their production forecast is to mandate that they provide a forecast (schedule) of their production to the system operator (at least by hour) and to establish an imbalance charge for deviation of their actual from forecasted production (imbalance charge). The incentive to avoid paying imbalance charges will motivate generators to better utilize weather data and forecasting techniques.

(27) Imbalance charges should be related to actual system balancing costs.

(28) Because of the uncertainties of weather forecasting, the combination of a long lead time for the mandatory scheduling (e.g. month, week or day-ahead) and high imbalance charges might undermine the profitability of intermittent RES producers. For this reason, the regulator should ensure that the system operator allows these producers to adjust their schedule intra-day as close to real time as possible.

Additional possibilities to improve system flexibility

(29) Some non-weather-dependent renewable producers, such as biomass or hydro plants, put no additional strain on system flexibility due to their ability to operate according to schedule. On the other hand, truly intermittent resources – wind and solar – can, in significant quantities, pose serious challenges to a system that was developed with a mindset of reasonable predictability.

(30) Regulators can choose one or more of the following potentially effective solutions to increase overall system flexibility. The regulator should consider the substantial difference in the cost of the options.

a. Aggregation. The high local variability of intermittent generation can partly be balanced out by geographic aggregation via consolidating smaller balancing areas into larger units. A complementary policy may be to mandate a more dispersed pattern of wind installations within a given control area, although such a restriction on locational choice can decrease the efficiency of wind resource utilization.

b. Pooling reserves among several control areas. Introducing a more flexible approach to control area (including cross border) interchanges (such as dropping the requirement that all secondary reserves must be procured from within the control zone) can allow cheaper reserves to be called in from neighboring territories.

c. Building new resources. A trivial, but costly solution to the flexibility problem is simply to build more power generation capacity that can provide system flexibility, such as CCGT or hydro units.

d. More frequent scheduling. See point (28) above.

e. Incentives through tariffs. In addition to mandating the payment of imbalance charges by intermittent generators, regulators can design tariff schemes to motivate other load-following units that are unable to provide regulation service to schedule their operations in such a way as to assist system flexibility. One example could be to discourage the production of biomass units at night, to allow enough gas-fired or hydro units to operate and provide downward flexibility to the system.

f. Storage and centralized control. In times when the level of production from intermittent sources exceeds electricity demand, energy storage in the form of compressed air, pumped hydro, flywheel units, or thermal storage (e.g. hot water) units become indispensable. Alternatively, as a short-term fix, system operators could be given direct control over the production of intermittent generation, while providing proper compensation to the owners of constrained units.

g. Demand response. Regulators could design incentives for large consumers to provide short-run system flexibility in much the same way as generators do. Many industrial processes are such that their electricity supply can be interrupted for a few hours without significant economic losses, which is often a less costly way of providing emergency reserves than having stand-by generation capacity.

h. Smart grids. Future upgrades of the electricity network (so-called smart grids) will likely allow an increased use of large scale automated demand response, further enabling the integration of weather-dependent renewable energy sources into the electricity system. An increased application of net metering devices should be part of this process.

Appendix V -- South East Europe Memorandum of Understanding

The conceptual framework for a governance structure could be based on the framework developed for the South East Europe Memorandum of Understanding (MOU) on Regional Electricity Market Development as a model.[33] In that MOU, the six countries agreed to establish day-ahead market integration with the aim of achieving at least one other signatory by July 2018 and cross-border balancing among all six signatories by December 2018.

The parties to the MOU are known as the Western Balkan six countries. These include Albania, Bosnia and Herzegovina, Kosovo, Macedonia, Montenegro, and Serbia. For each country, ministries, NRAs, and TSOs were signatories.

The MOU intends to create a regional power market initiative consisting of three main parts:

- Power exchanges;
- A regional balancing market;
- Making the best use of the already-existing Coordinated Auction Office.

To implement, the MOU has a number of objectives, including:

- Expand existing cross-border grid capacities.
- Adopt EU Network Codes and Guidelines in accordance with the EU energy acquis;
- Provide the reasonable resources to achieve the objectives;
- Support wider regional and European integration processes.

Tactical Approach:

- Establish a strategy execution framework with governing and execution procedures;
- NRAs will use their authorities to remove regulatory obstacles and monitor ongoing development at the technical and regulatory level.
- Ministries will support to help resolve legal or regulatory obstacles;
- Steering Committee comprising relevant regional stakeholders (e.g. TSOs, PXs, Ministry, NRA representatives etc.).

Milestones:

- Regional imbalance netting for cross-border balancing before 31 December 2016; (reserve sharing);
- Finalize cross-border balancing cooperation by 31 December 2018.

[33] https://www.energy-community.org/portal/page/portal/ENC_HOME/DOCS/4126415/3178C3FCD7C364E1E053C92FA8C0F233.pdf

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