PRINCIPLES OF REGULATION ON HARMONIZED RULES FOR CROSS-BORDER TRADE AND REGULATORY COOPERATION FOR MARKET INTEGRATION IN THE BLACK SEA

September 2013

This publication was made possible through generous support provided by the Energy and Infrastructure Division of the Bureau for Europe and Eurasia under the terms of its Cooperative Agreements with the National Association of Regulatory Utility Commissioners, No. REE-A-00-07-00050-00. The opinions expressed herein are those of the authors and do not necessarily reflect the views of the US Agency for International Development or US Government.

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Regulatory Principles for the Black Sea Region – New Chapters

(Final draft for approval: September 18, 2013)

Rationale for Expanded Principles

This document introduces the three new Sections to the core Principles document developed in 2011-2012. The core document (http://www.naruc.org/International/Renewable_Principles.pdf) consists of nine primary Sections focused on the regulatory support for the development and integration of renewable energy. The three new Sections are:

Section 10 - Harmonized Market Rules for Cross-Border Trade
Section 11 - Market Integration and Regional Regulatory Cooperation
Section 12 - Market Monitoring for Cross-Border Trade and Additional Regulatory Recommendations

These new Chapters expand the original scope and relate directly to the mechanisms and regulatory arrangements that support successful facilitation of harmonized cross-border trading and further developments of regional markets.

Introduction

(1) Former Sections (1 - 9) of the Principles concluded that an electricity market geographically extended beyond national borders could significantly enhance the opportunities for renewable resource utilization in the Black See Region. For example, a market environment that provides RES-E producers the freedom to sell electricity and/or green certificates not only on national but also on cross-border markets will increase the attractiveness of the sector for investors and will assure RES-E at a reduced cost for local customers. Also, the grid integration and balancing cost of intermittent RES-E generation can be significantly reduced by pooling reserves among several national control areas.

(2) It is easy to demonstrate that beyond providing RES-E related benefits, cross-border electricity trading and wholesale market integration can improve the aggregate economic welfare of the countries involved in expanded electricity trading. Improved consumer welfare due to reduced wholesale electricity costs in the importing country and the improved profitability of exporting generators is expected to out-weigh consumer and producer losses in the exporting and importing countries, accordingly. Clever institutional design for electricity cross-border trading can ensure that the majority of trade related welfare increase is transferred to end customers. An example is when the revenue from cross border capacity auctions (see later) is used, as a rule, to decrease regulated transmission tariffs.

(3) Harmonized rules for cross-border exchanges in electricity and for transmission capacity allocation will enable the implementation of flexibility measures in the form of joint

renewable energy projects between EU Member States and third countries. The implementation of joint projects provides opportunities for reducing the costs of fulfilling national renewable energy targets and facilitates the cooperation at the regional level.[1]

(4) The potential to extract the benefits of electricity market expansion beyond national borders, mentioned in section (1) provides the rationale for the forthcoming discussion on cross-border electricity transactions and electricity market integration at the wholesale level. First, we discuss these issues in general terms and refer to RES-E related specifics next.

Section 10
Harmonized market rules for cross-border trade

(5) We first distinguish *cross-border electricity exchange* by monopolistic companies from *cross border electricity trade*.

(6) *Cross-border electricity exchange* takes place between neighbouring countries when the transmission capacity between the two systems (interconnector) can only be used by monopolies. Access to the interconnector is not allowed for third parties. The simplest example is when both countries have vertically integrated electricity systems including generation, transmission, wholesale, retail and export-import functions. Under these circumstances, electricity exchange can take place in order to help each other in emergency situations or can be motivated by price differences between the two countries. If in a given time period the cheaper country has excess capacity, the more expensive country might be interested in purchasing this excess from the cheaper country. Interconnection capacity is used to execute the agreed exchange transaction. Neither national electricity markets nor a cross-border capacity market develops under these circumstances.

(7) In contrast, *the distinguishing feature of cross-border electricity trade is that non-discriminatory third party access is granted for certain market participants* (generating companies, consumers and/or traders) *to use the interconnection capacity*. The interconnection capacity is owned by the transmission company but some specific regulation obliges it to provide access to the capacity for these third parties. In other words, *the TSO is organising the cross border capacity market*. In this case the major cross-border trade supporting functions of the TSOs are

a. the allocation of available interconnection capacity to those demanding it; and

b. the management of congestion when demand exceeds available capacity.

(8) Harmonized electricity cross-border trading rules are necessary but not sufficient conditions for *electricity market integration* between two countries. Market integration assumes that

a. functioning national electricity markets exist in both of the countries; this in turn assumes that both countries provide the freedom for all local market participants

[1] On 18 October, 2012 the EU Energy Community's 10th Ministerial Council decided to adopt Directive 2009/28/EC (RES Directive). The Energy Community members from the regional group (Ukraine, Moldova) have already agreed to a binding RES target of 11% and 17% by 2020, respectively.

(including RES-E generators) to get into direct transactions with each other and also provide regulated access to local transmission capacities;

b. both countries provide the freedom for all market participants to get into direct transactions with each other across the border;

c. a functioning cross-border capacity market is operated by the TSOs.

(9) Ideally, on an integrated electricity market (wholesale) electricity price formation takes full account of supply and demand in both countries and ensures that cross-border interconnection capacities are most efficiently utilized. In case of sufficient available cross-border capacity, wholesale electricity prices of the two markets will be identical.

(10) A higher level of market integration might also involve the integration of national reserve markets, an issue especially relevant for RES-E grid integration.

General congestion management scheme

(11) Congestion denotes situations when the demand for power transmission exceeds the physical capabilities of the network. Congestion can be experienced both in internal and cross-border network sections. Congestion, however, occurs more frequently in relation to power transfers between countries (i.e. cross-border congestion) as interconnectors have been built – historically – more for security of supply reasons and less for trade facilitation and market integration.

(12) Congestion management is a series of actions to handle network access when congestion is present. It consists of the following sequential steps:

a. *determination of available capacity* i.e. the volume of power (expressed in MW) that can be transmitted for potential network users without compromising network security. The common grid model developed by the Black Sea TSOs can properly facilitate these calculations.

b. *capacity allocation* i.e. the distribution of available transmission capacity according to predefined rules (allocation method) among the participants wishing to utilize it.

c. once the transmission capacity has been allocated and the energy markets in both countries are settled, the TSO performs a *congestion forecast* on the basis of the most recent information on network conditions and generation dispatch to check whether the settled generation and consumption constellation is feasible. If network security violation is forecasted, the TSO takes measure to modify the generation patterns (*congestion relief, generation re-dispatching*).

(13) The entire process of congestion management – including the method of defining the available capacity, the timing and method of allocation – should be transparent and the relevant data published to market participants.

(14) Regulators should be involved in approving congestion management rules and be responsible to monitor and enforce their implementation.

Measuring transfer capacity

(15) TSOs announce to potential network users the transmission capacity of each border in both directions for different time periods as Available Transmission Capacity (ATC) and express it in MW.[2] ATCs are not necessarily equal in the two directions, as they also reflect the strength of the network neighboring the transmission line.

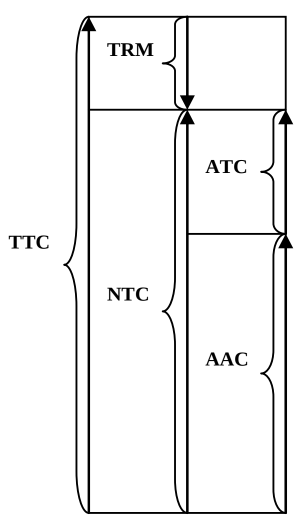
(16) Total Transfer Capacity (TTC) is the maximum power flow between two interconnected systems without violating system security. Transmission Reliability Margin (TRM) is a part of TTC that is reserved to cover forecast uncertainties arising from unexpected network events. For calculating the TRM the TSO utilizes historical cross border physical and commercial flow data and load-flow models.

(17) Net Transfer Capacity (NTC) is the expected maximum volume of transmitted power that is available for commercial transactions. NTC equals TTC minus TRM.

(18) The NTC is incorporated into the products offered by the system operator – annual, monthly and daily capacities. Whatever is not allocated as annual capacity is offered as monthly capacity and the consequent ATC is the NTC minus the already allocated amount (Already Allocated Capacity). The same logic applies for daily and intraday allocations. Note that multi-year long cross border trade contracts might significantly reduce (as AAC) cross border capacity available for shorter term transactions (ATC).

(19) All these values refer to the overall capacity between two systems, covering all interconnectors. However they are not simply the aggregate of the individual interconnector capacities.

Figure 1. Transmission capacity measurement concepts



TTC: Total transfer capacity
TRM: Transmission Reliability Margin
NTC: Net Transfer Capacity
NTC = TTC – TRM
AAC: Already Allocated Capacity
ATC: Available Transmission Capacity;
ATC = NTC – AAC

[2] Capacity refers to the admissible electricity current but considering the relatively stable voltage level, it can be expressed in terms of power flow (MW).

Determining transfer capacity

(20) The determination of available capacity is done by the TSOs of the interconnected systems. In NTC based allocation modes the general practice is that the two TSOs independently determine the NTCs (for both directions) and the smaller will be announced as NTC (again, both directions) in relation to the two countries. TSOs could also agree to use a common (load-flow) model for determining NTC values. In this case the commonly agreed NTCs will be applied.

(21) TSOs allocate forward transmission capacities (annual, quarterly, monthly, weekly) and shorter term capacities for physical deliveries (daily and intraday). In practice annual capacity is determined in all cases, monthly and daily capacities for most of the European borders. Intraday transmission capacity allocation is less widespread, but becoming more frequent with the progressive integration of European markets.

(22) Annual capacity is the capacity available throughout the year, even during times expected to be the most restrictive. The same applies for the later phases (monthly, daily and intraday) but with gradually better forecast and usually higher NTC values.

(23) NTCs for the respective phases should – as much as possible – show consistency so that market participants anticipate it from past values. The TSO should publish as early as possible changes in future NTC values that are foreseeable.

(24) In order to enhance cross border electricity trading and the related economic benefits, TSOs should allow access to the maximum available amount of cross border transmission capacity for market participants without jeopardizing system security. However, an integrated electricity company (inclusive of the transmission company) might rather have incentives to withhold cross border capacity from market participants. This is why it is a prominent regulatory task to ensure that the TSO indeed maximizes NTC available for market participants. Section 11 will discuss cross border market monitoring practices to support energy regulators detecting and correcting flaws in cross border capacity calculation, allocation and use.

Congestion relief

(25) As the NTCs for a shorter time period (e.g. month) are recalculated on the basis of the most recent information, the derived value is usually higher than the one set for the longer period (e.g. annual NTC). Similar logic applies in relation to the monthly versus daily allocations.

(26) If – for some reason – the recalculated (e.g. monthly) NTC is smaller than the amount already allocated for the longer time period (e.g. annual allocation) then the TSO has to curtail these already allocated capacities accordingly. It is important to note that such congestion relief measures are – in practice – only applied in case of unforeseen system events (emergency situations). TSOs have a mechanism in place for cases when another TSO

asks for a short-term increase or decrease of export balance (e.g. due to the interruption in the operation of a generation unit).

(27) It is very important from a regulatory point of view that the curtailment of allocated rights is avoided as much as possible. A possible solution – actually used in some countries – is the announcement of differentiated NTC within a single period (e.g. certain days have lower NTC at a monthly allocation).

(28) As allocated transmission capacities are valuable rights and their (partial) withdrawal incurs potential loss for their owner (i.e. it is not able to fulfill its commercial contracts), capacity curtailment – most often – involves compensation. In the EU, compensation is required in case of curtailment. According to a recent draft ACER framework guideline, the compensations shall be equal to the price difference between interconnected zones, within the relevant time frame. In cases when the curtailment occurred due to force majeure, the capacity which cannot be used shall be reimbursed on the basis of the initial price paid. At the same time, curtailments shall be applied in a non-discriminatory manner.

(29) It is rather difficult to determine the fair allocation of cost (and therefore compensation) due to re-dispatching, hence the TSOs tend to set the annual NTC conservatively in order to avoid the curtailment of allocated transmission rights and try to approximate real capacity more closely via the monthly, daily and intraday allocations, sequentially.

Since priority dispatch of RES-E generation is a common way to support RES-E producers, the rapid deployment of intermittent – primarily wind and PV – production is likely to increase the volatility and decrease the predictability of both internal and cross-border transmission capacity usage. In meshed networks massive intermittent generation will significantly increase unintended loop-flows.

(30) *Network loop-flows are unintended physical flows in third-party transmission capacities generated by a commercial transaction between two network locations. Loop-flows distort the physical operation and the economic regulation of electric networks. The unintended flows generated in far-away transmission capacities render network balancing, frequency and voltage control more difficult in the affected system. Additionally loop flows cause unintended and uncompensated economic costs to the affected electricity system. The business opportunity to utilize transmission capacities is reduced.*

(31) Under extreme conditions increased loop-flows can result either in the curtailment of RES-E production (short term), the reduction of announced NTCs (especially in the longer periods due to the uncertainty of intermittent production schedules) or – as a last resort – congestion relief. The reduction of capacities offered to the energy traders, i.e. the lower utilization rate of the cross-border network, results in welfare loss. This can be alleviated by transmission capacity expansion. A more cost effective way though is to improve the efficiency in using already existing transmission capacity through shorter time periods for transmission capacity allocation (intraday). This will be able to utilize additional information from improved short term intermittent generation forecasts.

Capacity allocation methods

(32) The task of cross-border capacity allocation and pricing is especially relevant for time periods when the demand for cross-border capacities exceed the amount available for trade.

(33) Capacity allocation – regardless the actual method applied – should be transparent and non-discriminatory. This means that all capacity requests should be treated equally i.e. regardless of any characteristics of the applicant other than those that are used in the allocation method.

(34) Several transmission capacity allocation methods are used in Europe and worldwide that can be characterized along four dimensions:

a. the basis of calculation (NTC or flow-based)

b. separation versus integration of cross-border capacity and energy markets (explicit versus implicit methods)

c. logic of allocation (administrative versus market based)

d. level of harmonization of TSOs (bilateral, common, coordinated) (Figure Figure 1).

(35) The NTC based capacity allocation modes – similarly to all other allocations – have to consider the amount of power flows at other borders. NTC is set at a lower level implicitly considering the previously experienced power flows of the other borders and allowing for uncertainties. As a consequence, the observed physical flows often surpass the allocated capacity by a considerable margin rendering the capacity factor (utilization factor) of the network connection very high.

(36) Flow-based allocation (FBA) – in contrast – reflects the actual distribution of power flows in the adjacent areas and as such provides a better approximation of the capacity that can be allocated safely. Its main advantage is that it allows for the relaxation of overly stringent cross-border capacity restrictions that especially characterize highly a meshed network such as of continental Europe. Its disadvantage is that it requires complex computation and agreed modeling methods by all involved TSOs, making FBA more difficult to apply.

(37) The common feature of explicit allocation methods is that the transmission capacity and the energy markets are separated and the settlement of these two markets is sequential: first the capacities are determined then the energy flows. Market participants hence bear the risk that the two volumes do not match: allocated transmission rights limit trading options or unused capacities create loss (if not received for free) to the actor.

(38) Under implicit methods (i.e. auctions) capacity rights are not allocated to individual participants but are internalized in the settlement procedure of the electricity markets (see the Market Coupling section).

(39) Many European TSOs still use NTC based explicit allocation methods, whereas the direction of proposals (ACER) is to migrate to implicit NTC or flow-based methods more compatible with the future single Internal Electricity Market of Europe.

(40) Capacity allocations generally apply the ”use-it-or-lose-it” rule, meaning that excess rights (that become manifest at the moment of energy market gate closure) can be reallocated by TSO again in the remaining short period of time.

(41) The more frequent the allocations are, the better the overall capacity utilization rate of the cross-border infrastructure.

(42) The creation of a secondary market for transmission capacity rights can contribute to the efficient final allocation of physical transmission rights. The secondary market is based on a “use-it-or-sell-it” principle. Due to the different timing of capacity auctions and energy trading, the market participant is often left with too much or too little capacity as he/she does not know in advance the exact traded volumes. This problem is especially true when capacities are allocated only to longer periods (i.e. no day-ahead and intraday). This can induce capacity right hoarding and unused capacity rights. Secondary market transactions can ease the inflexibility of forward physical transmission capacity markets.

(43) The TSO (or a CAO) can have the role of approving secondary market transactions for cross-border capacity.

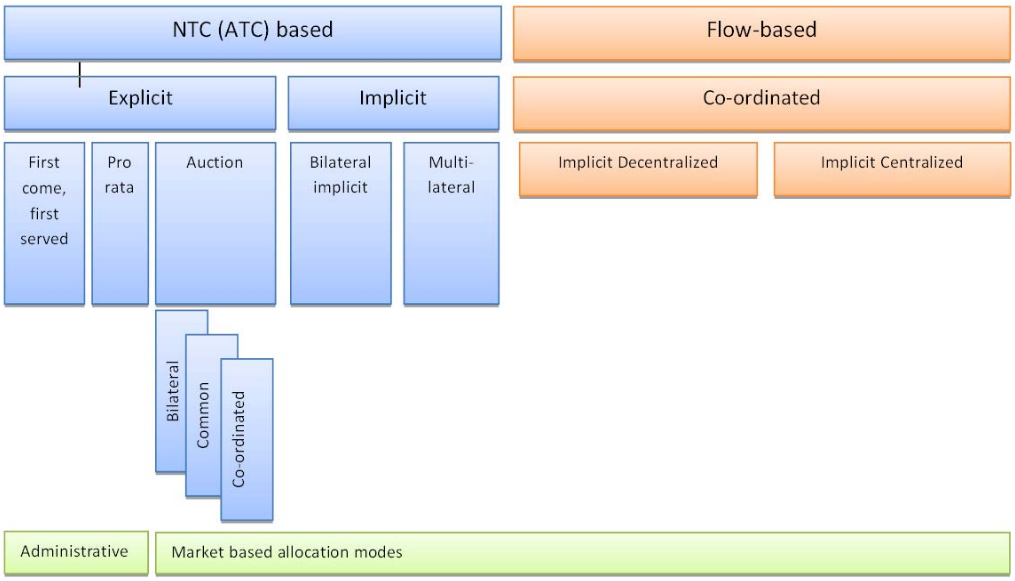
(44) Regulation should eliminate the potential interest of the TSO to decrease ATC in order to increase its own revenues or for any other reasons. For this reason any revenues resulting from the allocation of cross-border capacities should exclusively be used for the following purposes in the European Union:

a. guaranteeing the actual availability of the allocated capacity

b. network investment to maintain or expand cross-border capacity

c. reduction of network tariffs (considering it as income in the transmission tariff setting process)

Figure 1. Capacity allocation methods



Administrative and market based capacity allocation methods

(45) We can differentiate between administrative and market-based cross-border capacity allocation methods.

(46) The two main versions of *administrative allocation* are the “First come, first served” and the pro rata allocation.

(47) In case of “First come, first served” allocation, the capacity right is granted for free according to the temporal order of capacity requests received by the TSO until there is no further available capacity. Although administrative allocation is not efficient (its – zero – price does not reflect the economic value of this scarce resource), it is a valuable model for allocating capacities in the time window between the day-ahead capacity allocation and the actual electricity delivery. In this case there is no time for more profound allocation procedure for the still available capacity (capacities unused due to the ”take-it-or-lose-it” rule) but the remaining capacities can still be allocated and used by the applicants. Capacity rights can be allocated for free or at a price, but in the case of the above mentioned last minute allocations it is usually for free.

(48) The pro rata allocation means that all requests are accepted but only partially as a fixed share of the total request and total available capacity. Capacity rights can be allocated for free or at a price. The price of the capacity in the latter case is not market based but determined by the TSO or the regulator on e.g. cost basis. This allocation mode allows for the strategic behavior of bidders as they – knowing in advance that the required amount will be cut pro rata – bid for amounts higher than they are willing to pay for. As a result those actors who would be willing to pay more lose the same share of their request.

(49) Explicit auction is a market based and the most widely used allocation mode. It can be executed on a bilateral basis or in a coordinated form. A single country can employ different types of explicit auctions at its various borders.

(50) When capacity auctions are used for the allocation of cross-border capacities, the price of the capacity is determined by the auction's outcome. The demand for capacity is determined by the bids of market participants. Bids indicate the required capacity and the price the bidder is willing to pay for it. The TSO can e.g. order the bids into descending order and allocate the capacity for those who are willing to pay the most for it until the available capacity is fully allocated. In this case the price of a MW of cross border capacity will be equal to the last bidder's offer price who still received capacity at the auction. Note however that the TSOs apply different auction methods to allocate cross-border capacity.

(51) The auction price of a MW of cross-border capacity for a given hour will, as a rough rule of thumb, reflect the wholesale price difference of a MWh of electricity between the two countries.

(52) Explicit auctions – due to the sequential clearance of the transmission capacity and the energy markets - can facilitate the exercise of market power of a dominant generator. For example, if the dominant generator holds a significant share of the transmission capacity then it has an incentive to raise the energy market price in the importing region and is able to do so via withholding generation capacity and capture the resulting rent.

(53) In the bilateral form the two TSOs independently determine the NTCs (for both directions) and the smaller of the two will get allocated. In some cases the two TSOs involved split the available capacity and allocate their own share (split auction), in other cases one of the TSOs or an independent office is mandated to allocate the capacity on behalf of both TSOs (common auction). In all cases the TSOs define NTC for each common border simultaneously whereas power flows are interrelated with adjacent borders. As a consequence TSOs are likely to define over-restrictive NTCs.

(54) Coordinated explicit auctions provide a solution to this problem as TSOs set the NTC jointly and hence can accommodate the interaction of NTC setting at various borders. Additionally, traders do not have to acquire separate transmission capacity right for the whole route but only a single one.

(55) The advantages of market based allocations are:

a. provides revenue for the TSO
b. provides investment location signal for the TSO
c. provides incentives for the TSO to increase NTC to the maximum within the security limits
d. the allocation of transmission capacity is based on the willingness of applicant to pay for the right, which reflects more closely the economic value of the capacity.

(56) Revenues and revenue sharing rules/agreements among TSOs deserve special attention from the regulator. As a rule, auction revenues are better to allow for expanding congested lines or to reduce transmission tariffs for the benefit of end customers. A part of the revenue can be allowed to remain with the TSO to encourage it to efficiently

manage the cross border capacity market. Usual scrutiny of the regulator over regulated revenues should apply. Revenue sharing agreements should be reviewed and approved by the relevant regulators.

Coordinated capacity calculation and allocation

(57) A major step towards electricity market integration might be when dedicated TSOs set up a joint central cross-border capacity allocation office, often called as Central Allocation Office or Coordinated Auction Office (CAO). Setting up a CAO requires sufficient size of the resulting market, as economy of scale is needed to finance its operation.

a. Taking the example of the Central and East Europe (CEE), a CAO might benefit countries of the Black Sea region. The CEE CAO was established as a joint company of eight TSOs to perform the long term and day-ahead calculation and allocation of cross-border capacity within the region. The CAO has been handling the regional capacity calculation and allocation tasks of the CEE TSOs since November 2010. It conducts yearly auctions and has been carrying out monthly and daily auctions as well.

b. The CAO secures fully harmonized and coordinated allocation rules so it reduces transaction costs associated with cross-border trading. Setting up the joint allocation offices has certainly enhanced wholesale competition in the region.

Section 11
Market integration and regional regulatory cooperation

(58) Electricity market integration requires more than efficient and harmonized rules for cross border electricity trading. It also requires the integration of electricity market transactions of the interconnected electricity markets. In this text electricity market integration is discussed in the context of recent EU experience with electricity market coupling.

Context of Market Coupling

(59) *Market Coupling (MC)* is an implicit auctioning method to efficiently allocate cross-border transmission capacities. Instead of organising explicit cross-border capacity auctions, the system operator makes unreserved capacities available for market coupling. The power exchanges in each country (price zones) involved in MC balance demand and supply bids by also considering the prices quoted on the exchanges of neighbouring price zones. In this way cross-border transactions do not have to be supplemented with separate transmission capacity rights allocation.

a. In its *narrow definition* Market Coupling refers to the integration of the day-ahead markets only, as this is the market segment, where market coupling is the most advanced. Other market segments (intraday, forward or balancing markets) have specific features that make them more complex to integrate across borders. Rare examples for the latter are the integrated North European balancing market or the North West Europe pilot project to integrate intraday markets. North American RTO markets also offer examples of MC for hourly and shorter times.

b. In a *broader definition* market coupling embraces all the necessary steps for integrating electricity markets in different areas (e.g. day-ahead markets, forward markets, intraday markets, balancing markets), including institutional, regulatory and market design elements.

(60) When TSOs or regulators consider coupling two interconnected day-ahead markets currently divided by a national border, firstly they should make sure that their national day-ahead energy markets involve an organized electricity market (power exchange). In addition, various rules and procedures of both markets must be harmonized beforehand, like types of traded products, gate closure times and other operational procedures.

Preconditions of Market Coupling

(61) *Embrace market coupling – but carry on unbundling*. Firstly, it is important to note that in the countries of Central and Eastern Europe and of the former Soviet Union, unbundling of the vertically integrated electricity companies is a primary condition to further market integration. In countries with large incumbent companies that still own or indirectly control transmission grids *and* generation capacities *and* wholesale monopoly rights *and* long-term import-export contracts *and* the system operator, it is very difficult to arrive at competitive domestic markets, harmonized rules for cross-border trade or, eventually cross-border electricity market integration. The examples of more developed electricity markets following various ways of interregional market integration or market coupling regimes have shown remarkable welfare benefits. Market coupling or any other market integration regime would only deliver benefits to the electricity markets if strategic behavior of incumbents is fundamentally disabled. In order to successful integrate interregional markets regulators first have to administratively disintegrate their national monopolies.

(62) An additional precondition of market coupling is the *existence of independent energy and transmission capacity markets*. The key term is “independent”: successful market coupling presumes energy markets operated by organized power exchanges and cross-border transmission capacity markets operated by TSOs. Having any of them under the strategic control of major market participants would undermine efforts to put market coupling in place.

(63) *Sovereignty of national transmission networks.* There is another dimension to independence here that is important for the countries in the Black Sea region: it is very likely that they wish to maintain the sovereignty of their national transmission networks

and treat cross-border flows separately. Thus the European market coupling model developed to integrate sovereign national networks has more lessons to offer and looks politically more feasible than the overseas market models based on nodal pricing – even if those integrate regional electricity markets more efficiently. For instance, the MISO can couple its energy markets with adjoining regions in the US and Canada because it also acts as the TSO. Because US RTOs act as TSO and power exchange, US models are not directly transferable to the Black Sea Region.

Advantage of Market Coupling against explicit methods

(64) The ultimate aim of MC is to increase trade opportunities amongst participating countries on the existing interconnection lines, and hence maximize the combined welfare of those participating countries. If day-ahead markets work as auctions, the clearing of two neighbouring day-ahead markets can be performed jointly, automatically enabling supply and demand bids to be available from the other zone as well, as long as cross-border transmission capacity is available. Various advantages of such a system arise.

a. Each market participant sells and buys energy in its home market, and inter-zonal arbitrage opportunities are exploited routinely by the market coupling mechanism.

b. When two markets are coupled, all cross-border capacity between them is, by design, allocated to the transactions with the highest arbitrage potential, and by definition, the price of capacity is equal to the eventual energy price difference of the two zones.

c. There is no separate transmission capacity auction, the capacity is allocated implicitly.

d. In the longer term, by creating transparent markets and clear price signals on network scarcities, market coupling enables participating countries to optimally plan their transmission system developments in the future.

Alternative ways to accomplish Market Coupling

(65) Market coupling can be accomplished on the basis of alternative cross-border capacity calculation methods.

a. One option to calculate unreserved transmission capacities available for market coupling is to calculate net transmission capacity values (NTC) or available transmission capacity values (ATC).

b. The other option is to do flow-based capacity allocation (FBA). In this case the capacity made available for transactions within the framework of MC is estimated by simultaneous load-flow calculations that forecast actual physical network flows assuming potential production and load patterns within the participating area.

c. Following an FBA method is a possibility even if market coupling have been started on an NTC basis before.

(66) The main drawback of NTC (or ATC) based capacity calculation and allocation is that it results in overly stringent restrictions on cross-border trade, and therefore hamper a more efficient use of the existing transmission network. This is especially the case in a meshed network – such as the one in continental Europe -where bilateral NTCs must be determined low enough for the grid to withstand a “worst case” congestion scenario on all trading directions. The fundamental reason for this is that NTC based allocation poorly recognizes network loop-flows.

(67) *Flow-based capacity calculation and allocation solves the problems inherent to NTC based allocation.* Flow-based capacity calculation and allocation is to be preferred if substantial loop-flows are present. Flow-based calculation prevents cross-border trading from having unaccounted effects on third parties unaccounted for. With flow-based methods, the security assessment and the capacity allocation is essentially integrated, enabling the system operators to adapt the security checks to the actual trading needs of the market, instead of a worst case scenario. In theory, therefore, a flow-based mechanism should allow for more trade overall, and especially in the directions that are more valuable to market participants, increasing the total surplus attainable in the market.

(68) NTC based market coupling is inevitably less powerful than a flow-based alternative – but having no market coupling at all is the worst of possible options. The complexity of an FBA exercise may keep market coupling off the agenda for too long. Having NTC based market coupling is certainly much more beneficial for the markets to start out with than having no market coupling at all.

Regional regulatory cooperation

(69) It is apparent that enhancing cross border trading and accomplishing electricity market integration is a very complex and demanding regulatory task. Given the political support for such a process, regulators will need to establish conditions for a focused work to support the integration process. The involvement of other major stakeholders (most prominently the affected TSOs) into this process is inevitable.

(70) A proper start for regional regulatory cooperation is to assess the participants’ present cross-border trading regimes and then the drafting of a regulatory guideline for harmonized cross-border access and trading rules. Operational cross-border capacity markets are easier to establish than creating fairly well functioning local electricity markets. Cross border capacity markets can also enhance cross-border trading opportunities between countries with fairly different local electricity market models and could increase trade related benefits for the participating countries.

(71) An operational cross-border capacity market could also provide RES-E generators the opportunity of exporting their production. It is also a crucial component of a

regulatory environment in which it is feasible to start discussions about pooling reserve capacities across countries.

(72) The guideline for harmonized cross-border access and trading rules should be developed without regard to the source of electricity. Thus, the same rules should apply for RES-E and conventional generators in getting access to cross-border capacities.

(73) Another component of regulatory cooperation can be to provide RES-E generators the opportunity to sell their ‘green certificates’ beyond the borders of the country of their production. The revenue of the RES-E producer is composed of its revenue from electricity sales and an additional support. This support can take the form of a price subsidy (in the form of a feed-in tariff or feed-in premium) or the opportunity to sell the green certificate attached to green electricity production. Due to the very low variable cost of production and the priority dispatch guaranteed for RES-E generators, selling the electricity locally might be the preferred option for the rest of the region’s RES-E producers. However, a harmonized green certification system in the Black See region could allow RES-E generators to sell their certificates where they can get the highest revenue for it. However, work in this area might have a secondary preference compared to the work on a guideline for harmonized cross-border access and trading rules.

(74) Regulatory cooperation aiming at deeper electricity market integration is feasible only for those participants that have already achieved a substantial progress in developing their local electricity markets.

Section 12
Market monitoring for cross-border trade and additional regulatory recommendations

(75) In the European model, the amount of cross-border trading is limited by the Available Transmission Capacity of transmission facilities. Available Transmission Capacity is determined by Transmission System Operators. Accurate and commercially neutral calculations are necessary to maintain reliability of the systems and at the same time allow maximum trading.

(76) Market monitoring describes the methods regulators can use to observe and verify the accuracy and neutrality of these calculations.

(77) In electricity markets in the United States, market monitoring is contracted to specialized third-party firms. In Europe, in-house monitoring by the regulator is a more common approach.

(78) The goals of market monitoring of cross-border electricity trading are to:

a. Ensure competitive and efficient trading.

b. Provide improved transparency in the electricity markets.

c. Give confidence in the markets.

d. Achieve the benefits of competition for the benefit of consumers and producers of electricity.

(79) Monitoring of electricity markets looks for:

a. Flaws in the cross-border trading rules, or within the rules of the linked markets, that create inefficiencies or gaming opportunities.

b. Improvements to market efficiency.

c. Market power abuses and manipulation.

Relationship to regulators

(80) Monitoring is a process by which regulators first observe conditions and activities in electricity trading markets; the prices and frequency of bids, offers, and transactions; and the number and type of participants. The process also includes analysis of these observations to reveal market trends and sustainability. This information supports regulatory decisions with respect to rules, prices, and enforcement actions.

(81) Monitoring functions can be performed directly by the staff of regulatory agencies. Doing so requires a substantial commitment of staff time, development of advanced skills, and communications and data processing capability. Some level of direct market observation helps build and maintain regulatory understanding of market conditions.

(82) Third-party monitoring firms can significantly supplement the direct observations of regulators. The monitoring process requires highly specialized skills in electricity market analysis and in data processing that may not be available to regulatory agencies.

a. Third-party monitors can assist regulators by closely observing the conduct of market participants and market operators. Market participants and operators may be willing to provide more candid information to a third-party than to a regulator.

(83) Regulators can design the reporting coverage and procedures for contracted market monitors. Market monitors can provide reports on market conditions, suggested improvements, and suspected abuses or violations. Reporting may include advice, recommendations, and reporting to regulators, market operators, market participants, and other regulatory bodies. Frequency and content of reports can be tailored to market and regulatory needs.

(84) Reported information might include market power, abuse of market power, market manipulation, market performance, and operator performance.

(85) Regulators should reserve to themselves the function of formally investigating suspected violations of regulations and statutes and any enforcement actions that result from the investigation. The role of the market monitor with respect to a particular matter ends when the monitor’s information is given to the regulator.

(86) In the U.S., the Federal Energy Regulatory Commission has not allowed market monitors to perform any actual market operations. That role is reserved to market operators, ensuring the regulatory responsibility of the market operator. The FERC does not directly regulate the functions of independent market monitors.

(87) In the EU, the Agency for the Cooperation of Energy Regulators has the authority to monitor wholesale energy markets in close collaboration with national regulatory authorities in order to prohibit abusive practices affecting wholesale energy markets. Monitoring covers the potential for manipulating cross border transactions.

Independence of Market Monitors

(88) A contracted monitor should be separate from market participants and from market operators. Conflict of interest rules should apply to market monitor personnel as well as the firm.

(89) Regulators should assure that the monitor has adequate budget, staff, resources, and access to market data. Necessary skills include economics, engineering, software developers, mathematics, and statistics.

Monitoring process

(90) Market monitoring is performed through continuous access to market data. That data includes bids and offers for power as well as the prices for actual power. Study of unsuccessful bids and offers may reveal market conditions more effectively than transactions alone.

(91) Real-time market data are screened to identify circumstances that require further investigation. This step requires software designed for the market being monitored.

(92) Data are analyzed based on observations or complaints. The market monitor must be able to receive complaints by market participants about suspected actions by competitors.

(93) Analytic tools include knowledge of generation types and fuels, typical cost patterns for each generator, and expected operating ranges. The analyst must have access to actual market bids and offers made by participants. Screening techniques are used to indicate bids and offers outside expected ranges.

Further recommendations

(94) *Develop the Regulator's capacity to monitor and control the strategic behavior of owners of physical transmission rights.* The owners of physical transmission rights are in a position to retain part or whole of their cross-border capacity from the market and enjoy the resulting increase in market power in at least one of the three following markets: the

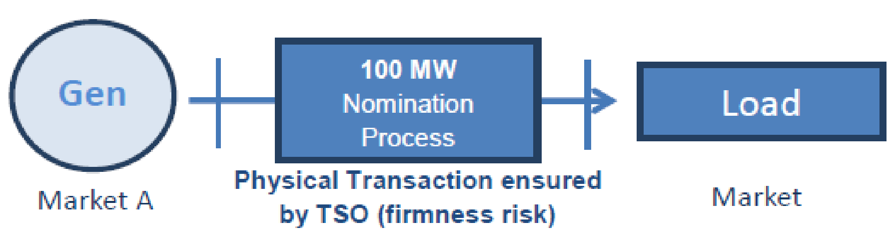
wholesale electricity market, the generation market in the higher-priced zone and the transmission capacity market. Customers, on the other hand, suffer significant losses and, as usually the case with incidents of market power, the welfare balance at the society level ends up vastly negative, with consumers losing much more welfare than the extra benefit that transmission capacity retention pays to the culprits. The most common regulatory remedy is the "use-it-or-lose-it" principle.

(95) *Enhance the share of cross-border capacity allocated in day-ahead markets as opposed to long-term explicit auctions.* In Europe currently only around a third of capacity is allocated in day-ahead markets and the rest is allocated on a long-term basis administratively or by auction. Market coupling is a well-proven method to integrate day-ahead markets and, in order to make it effective, a critical share of the day-ahead capacity allocation is necessary. The appropriate share is to be judged or experienced by national operators.

(96) *Provide market participants with proper means to manage the risks of unforeseen price changes in neighboring pricing zones.* Price spread volatility between electricity markets creates the need for derivatives, which allow market participants to hedge against the market price differences which result from transmission congestion. There are different forward hedging products that can be offered to hedge the risk associated with congestion between different markets. A possible option is to hold a transmission capacity product, which can be a physical or financial transmission right.

(97) A Physical Transmission Right (PTR) gives the holder the exclusive right to use a particular interconnection in one direction to transfer a predefined quantity of energy from one market to the other. Figure 3 below shows an example when a Generator in market A produces energy in order to meet his contract of supply in market B. In the case of physical contracting it is usually the Generator who will secure interconnector capacity ahead of time (here we consider long-term rights). He will pay a certain price in the primary auction and nominate the energy to be transmitted. In this simple example the load in market B is physically served by using the right to transfer 100 MW from market A to B without any participation on day-ahead markets.

Figure 3. The example of physical transmission rights

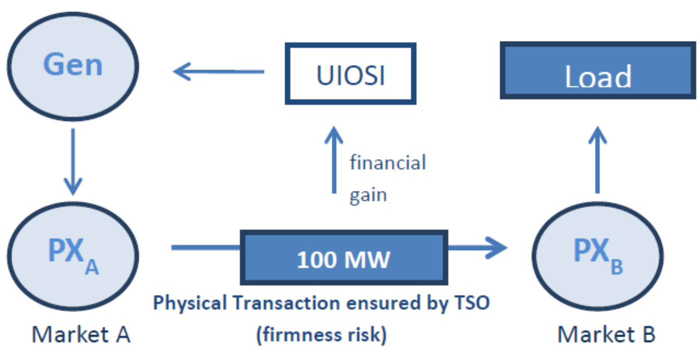


(98) The responsibility for the process of capacity determination and allocation of transmission rights is carried out by the TSOs (or by an entity acting on behalf of the

TSOs). The exercise of PTRs as options is performed through a nomination process. In order to be able to nominate capacity, PTR holders are usually requested to sign Nomination Contracts and/or Balancing Responsible Contracts (depending on the country). This yields that the PTR is always linked to any sort of UIOLI (use it or lose it) or UIOSI (use it or sell it) optionality when system operator automatically re-auctions the non-nominated capacity without any compensation (in the case of UIOLI) or resells it on the shorter market on behalf of the holder, who receives the resale price (in the case of UIOSI).

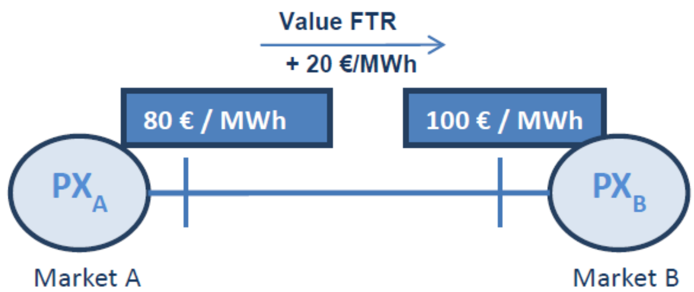
(99) The owner of the PTR can also decide to use it as a Financial Transmission Right (FTR) according to the UIOSI provision, as PTRs with UIOSI entitle their holders to carry out electricity transfers and give them the opportunity to manage price differences in opposite direction to their transaction by not nominating the PTR. If the holder does not nominate the right, it gets resold in the day-ahead market. If market coupling is in place, the owner of the PTR receives the price difference between area A and area B. Otherwise (in case day-ahead explicit auction still in place) the holder receives the price of the day-ahead explicit auction. In this case the Generator will have to participate on the day-ahead level as a seller in market A and as a buyer in market B in order to comply with his energy supply contract in market B (see Figure 4).

Figure 4. Physical transmission rights with use-it-or-sell-it condition



(100) In contrast to a Physical Transmission Right, which enables the holder to use a transmission line, the Financial Transmission Right is a purely financial instrument (is not a physical right of transfer power between markets) which hedges the buyer against the price difference between markets. The underlying condition for FTRs is the introduction of a functioning day-ahead market coupling. FTRs can be options and obligations. FTR as an option entitles its holder to receive a financial compensation equal to the positive market price differential between two areas during a specified time period in a specific direction. FTRs as obligations in contrast also oblige holders to pay for a negative market price differential. Figure 5 illustrates FTR as an option for a given time period.

Figure 5. Example financial transmission rights as an option



(101) As there are no physical rights to flow energy between the markets, the Generator has to participate in both markets to ensure the supply of energy. In this example the Generator in market A would sell to market A at a price of 80 €/MWh. He serves the load by buying the energy directly in market B at a price of 100 €/MWh. The loss of this transaction would amount to 20 €/MWh. However this equals the FTR payout of +20 €/MWh. Assuming the above market prices, the value of the FTR (here +20 €) provides price certainty for its holder and is thus an efficient hedging towards price spread volatility. In the case of market coupling the same rationale applies to non-nominated PTRs which are resold in the Day-Ahead market coupling. In terms of risk hedging, FTR options are completely equivalent to non-nominated PTRs with UIOSI. However FTRs has an advantage that they have a purely financial character, without any nomination process and thus they require lower contractual and technical effort. Less complexity could therefore lower the market entry barriers and consequently could increase competition.