Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity

Initial Impact Assessment

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1 PROCEDURAL ISSUES AND CONSULTATION OF INTERESTED PARTIES

1.1 The Issue of CACM - History and Background Information

The underlying aim of the European Internal Electricity Market (IEM) is to introduce competition between market participants, in anticipation of market oriented and transparent prices for electricity that should result out of that, to the benefit of European electricity customers. Indeed, recalling the initial background of the discussions in the early 1990s in electricity markets in the EU, the purpose of the electricity market liberalisation in Europe follows (*www.ec.europa.eu/energy/electricity/publications/index_en.htm*):

"…

- *Increase efficiency by introducing competition*
- *Leverage the EU electricity prices to become "real", comparable to the US or Australia*
- *Ensure essential public services and obligations by appropriate measures in the competitive single electricity market*
- *Reduce the required reserve capacity by sharing it*
- *Improve efficiency and avoid wasting resources in generation - competition is good for efficiency*
- *Freedom of choice to the customers with a diversification of the supplier selection criteria*
- *Improve service to the customers as otherwise they will switch*
- *Lower electricity prices → lower production costs for the EU industry → lower products' prices for the EU citizens (and higher competitiveness for the EU industry at the World market)*

…"

Since electricity needs to be transported over networks**,** non-discriminatory access to the networks and cross-border trade over interconnections between control areas is a vital precondition for establishing a competitive IEM in the EU.[1]

Capacity Allocation and Congestion Management (CACM) for Electricity has been a topic on the Florence Forum agenda since its early days[2]. As the interconnection capacity is often scarce and it is not always feasible to accommodate the physical flows resulting from commercial transactions, the functioning of electricity markets is strongly dependent on how the interconnection capacity is allocated and how congestion in the networks is managed.

[1] Analysis of Cross-Border Congestion Management Methods for the EU Internal Electricity Market, by Consentec and Frontier Economics; a study commissioned by the European Commission, Final Report June 2004. http://ec.europa.eu/energy/gas_electricity/studies/doc/electricity/2004_06_congestion_management_methods.pdf

[2] http://ec.europa.eu/energy/gas_electricity/forum_electricity_florence_en.htm

An important step towards enhancing capacity allocation and congestion management has been achieved by the adoption of Regulation (EC) No 1228/2003 (First Regulation) and the annexed Congestion Management Guidelines 770/2006/EC (First CM Guidelines)

Although the First Regulation and the First CM Guidelines contributed significantly to improved CACM, the integration of national markets by means of efficient and effective use of interconnection capacity did not proceed as expected.

One important shortcoming was the lack of coordinated congestion management between the control areas. This topic has been a focus of numerous discussions and studies by the European Commission, ERGEG, TSOs, power exchanges and market participants. An exhaustive and detailed study[3] commissioned by the European Commission (the Commission) resulted in the subsequent joint work by the European Transmission System Operators for Electricity (before ETSO, now ENTSO-E) and the Association of European Power Exchanges (EuroPEX).

The first results of this cooperation were presented at the XV Florence Forum in November 2008 and led to the establishment of the Project Coordination Group (PCG) with participants from the Commission, ERGEG, ETSO, EuroPEX, Eurelectric and EFET.

The PCG was charged by the Florence Forum to develop a practical and achievable model to harmonise EU-wide Capacity Allocation and Congestion Management. PCG was requested further to propose a roadmap with concrete measures and a detailed time frame, taking into account progress achieved in the ERGEG Electricity Regional Initiatives (ERI). In addition, the Florence Forum tasked the established Market Integration Design Project (MDIP), which was overseen by the PCG and involved TSOs and Power Exchanges, to address the practical design and implementation issues for the EU-wide CACM.

The PCG reported on the work undertaken in MDIP on capacity allocation and congestion management to the XVI and XVII Florence Fora[4]. At the XVII Florence Forum in December 2009, it was decided to take forward the PCG's work in ERGEG's Ad Hoc Advisory Group (AHAG). In addition to PCG members, AHAG was extended to include organisations representing large consumers of electricity (International Federation of Industrial Electricity Consumers – IFIEC and European Chemical Industry Council - CEFIC) as well as the European organisation representing wind generators (European Wind Energy Association - EWEA).

The role of AHAG has been to function as a working group from which ERGEG can request advice on its work on capacity allocation and congestion management. AHAG was further requested to coordinate and give guidance to the three specific projects on Governance (chaired by the Commission), Capacity Calculation and Intraday Trade (both chaired by ENTSO-E).

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[3] Analysis of Cross-Border Congestion Management Methods for the EU Internal Electricity Market, by Consentec and Frontier Economics; a study commissioned by the European Commission, Final Report June 2004. http://ec.europa.eu/energy/gas_electricity/studies/doc/electricity/2004_06_congestion_management_methods.pdf

[4] http://ec.europa.eu/energy/gas_electricity/forum_electricity_florence_en.htm

Whereas the findings from the Governance Project are an important input for the future FG on Capacity Allocation and Congestion Management for Electricity, the results of the other two projects are of a more technical and detailed nature, thus considered particularly relevant for the future related CACM codes.

1.2 The 3rd Package

The First Regulation and the First CM Guidelines have been replaced by Regulation (EC) No. 714/2009 (hereinafter the New Regulation) as part of the 3rd (Legislative) Package[5] that was adopted 3 September 2009 and will become applicable on 3 March 2011.

The 3rd Package defines a new European regulatory framework with framework guidelines and related codes. It also establishes an EU Agency for the Cooperation of Energy Regulators (ACER) that will focus on cross-border issues and the internal market. ACER will be responsible for preparing framework guidelines. The New Regulation also promotes cross-border collaboration and investment within the new European Network for Transmission System Operators for Electricity, ENTSO-E, and similarly ENTSO for Gas. ENTSO-E will be responsible for developing related network codes for electricity.

At the heart of the 3rd Package is the development of EU-wide network codes on topic areas for the integration of EU electricity and gas markets, enabling cross-border trade and competition to develop across EU energy markets. The process for developing these codes is stipulated in the legislation and includes the elaboration by energy regulators (ACER) of framework guidelines (FG), which set out the key principles for the development of the network codes by the transmission system operators (ENTSO-E).

Since the provisions of the 3rd Package will not be applicable until 3 March 2011, ERGEG has been committed to making as much progress as possible in preparing the work on FG during the interim period and will therefore provide input to the European Commission and ACER on the preparatory work on FG.

The 16th Florence Forum in June 2009 outlined the essential elements of the 3rd Package and made suggestions on how to efficiently use the interim period in order to pave the way for the implementation. One of the key issues identified and agreed upon to be tackled[6] is capacity allocation and congestion management.

It is within this context that ERGEG has been invited by the Commission to draft a framework guideline on CACM – the background information and expected results are outlined in the 26 March 2010 letter from the Director of the Commission's Directorate General for Energy to the ERGEG President (enclosed in Annex I).

In order to ensure that the development of the FG meets the best regulatory practice, the respective CACM Project is organised in two steps:

[5] The 3rd Package proposals for the European Internal Market in Energy were finally adopted on 13 July 2009 and include 5 legislative acts, which can be viewed at: http://eur-lex.europa.eu/JOHtml.do?uri=OJ:L:2009:211:SOM:EN:HTML

[6] The other two being electricity Grid Connection and System Operation.

1. Step 1: Initial Impact Assessment for justification (this document); and

2. Step 2: Drafting of framework guidelines for CACM, 2 months of public consultation and revision of the framework guidelines accordingly following the consultation.

AHAG was considered also as the respective Expert Group on CACM, with the purpose of providing an input/assistance to ERGEG (later ACER) in relation to the specific issues relevant to a particular topic. The AHAG members are listed at www.energy-regulators.eu.

1.3 Organisation and Timing

This Initial Impact Assessment (IIA) has been prepared by ERGEG assuming the role “as if being the Agency”.

The work has benefited from the comments and advice from AHAG and the previous work undertaken by the PCG. Moreover, after the preliminary results were presented at the XVIII Florence Forum 10-11 June 2010, the IIA has undergone a substantial work of adjustment, extensions and taking into account in particular the issues of costs and benefits for the evaluated and envisaged policy options and solutions.

Article 6 of Regulation (EC) No 714/2009 (Regulation) on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 (old Regulation) sets out the provisions for the establishment of network codes. The European Commission shall request that ACER submits to it within a reasonable period of time, not exceeding six months, non-binding framework guidelines setting out clear and objective principles for the development of network codes relating to the areas identified in Article 8, paragraph 6 of the Regulation. ACER shall formally consult ENTSO-E and the other relevant stakeholders in regard to the framework guidelines. Following the preparation of the network code by ENTSO-E, ACER provides its reasoning and opinion to ENTSO-E on the draft code, which may then require amending by ENTSO-E. Once ACER is satisfied that the network code is in line with the relevant framework guidelines, ACER shall submit the network code to the Commission and may recommend that it be adopted within a reasonable time period.

In view of these provisions, ERGEG began preparing the work of ACER, which will not be fully operational until March 2011. During 2010, the regulators will complete framework guidelines on CACM.

From the procedural viewpoint, the planning is outlined further in the following block diagram in Figure 1, which shows the involvement of stakeholders in the development of the draft framework guidelines for CACM through workshops and public consultation.

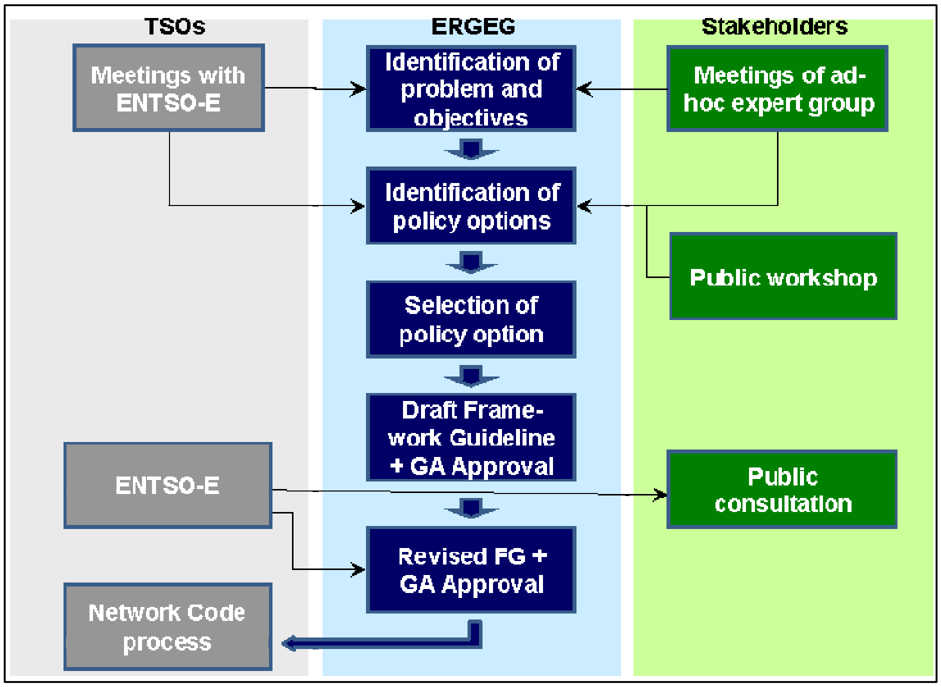

Figure 1: Block diagram of the process for the development of the framework guidelines

1.4 Consultation and Expertise

AHAG has been considered as the expert group in charge of advising and supporting ERGEG in the development of the FG for CACM.

AHAG members have participated in the work on this Initial Impact Assessment in their capacity as experts in their specific fields of expertise.

Before and after deciding on using AHAG as the Expert Group for CACM, ERGEG conducted a number of coordinating discussions with ENTSO-E and other stakeholders, within and outside of the scope of the Florence Fora, in order to exchange views and establish a preliminary common understanding.

1.5 Public Workshop

According to the process in Figure 1, ERGEG will conduct a public workshop on the CACM FG during the public consultation of the draft FG (envisaged in Autumn 2010).

2 PROBLEM DEFINITION

2.1 What is the General / Policy context?

The primary objective of European energy policy and legislation and consequently also of the national regulatory authorities (NRAs) is to promote a competitive, secure and environmentally sustainable internal market in electricity.

Physical interconnections are essential for IEM integration, because they provide opportunities to trade between national markets (control areas) and help to promote the development of liquid energy markets. The availability of interconnection capacity between markets sets the limits for the physical volume of energy that can be traded.

Historically, the electricity networks and the interconnectors linking control areas were planned and built on a national basis. As a result, one of the key challenges in the creation of an integrated IEM is the limited interconnection capacity between networks operated by national TSOs. This was recognised in 2002 Barcelona Summit, when Member States set a target for interconnection capacity of at least 10 percent of generation capacity.

Member States have further committed to ambitious and legally binding targets to promote sustainable energy. These commitments, such as a target to meet 20 percent of Europe's energy needs from renewable sources by 2020, will have a significant impact on Europe's generation mix. As a result, many Member States will have to substantially increase their deployment of renewable generation, with the biggest increase expected from wind generation. The characteristics of renewable generation, such as the variable and unpredictable nature of wind, present new challenges and opportunities for market integration. How to address this challenge needs to be considered in the design of common rules for cross-border trade in general and CACM in particular. Moreover, market integration is expected to reduce the costs associated with integrating variable generation, by providing alternative sources of supply and demand.

The nature of electricity today is that it cannot be stored in massive quantities and in an economically viable way. Therefore, in order to provide operational security, supply must always equal demand (plus losses in the network).

As the interconnections provide access to wider generation and demand mixes and promote trade and liquidity of the market, they (interconnections) also help to support security of supply. The variable and unpredictable nature of renewable generation, which will be massively deployed in the future, means that the operational security of the networks will become even more important in the future.

2.2 What is the Issue or Problem that May Require Action?

The primary problem to be addressed is the presently ***inefficient and sub-optimal use of transmission network capacity*** between and within the control areas in the EU.

National transmission systems of the EU Member States are interconnected with each other creating several synchronously interconnected areas. This allows electric power to be produced where it is most efficiently possible and then to be transported to the consumption sites where it is most valued (i.e. exploitation of the welfare gain).

However, the capacity of the interconnections linking the national transmission systems are often insufficient, which leads to situations where not all physical flows resulting from international trade (induced by market participants' operations) can be accommodated.

There are two ways to tackle the issue of insufficient cross-border transmission capacity. In the short term, it is important to ensure that capacity is allocated to market participants in a non-discriminatory way that optimises the use of the existing interconnector capacity. In the long-term, more interconnection capacity needs to be built. Nevertheless, to build "all possibly needed" interconnection capacity would not be economically viable, which is why congestion management will always remain an important aspect of the electricity market.

The CACM methods applied at many interconnections have not enabled ***market liquidity and formation of reliable prices neither in day-ahead nor - consequently - in forward*** electricity markets.

Inefficient and uncoordinated mechanisms to allocate capacity and manage congestion have hindered the development of liquid and robust energy markets with reliable reference prices. The lack of proper price signals leads to the sub-optimal utilisation of networks and generation resources, and also to sub-optimal investment signals. Moreover, such a situation also causes ***reduced welfare[7] for the customers and society as a whole***.

The value of electricity traded annually in European wholesale markets is over 150 billion €. The value of trade across control area borders is estimated at approximately 15 billion € per year. In a well-functioning, integrated, effective and efficient IEM, market participants would trade between the control areas and zones in order to respond to the price differentials such that electricity prices would converge and most welfare gain would be delivered to the market and customers. However, the prices of the e.g. European day-ahead electricity trade show that there are still significant (not rationally explainable) price differences between the control areas and zones (regions).

Inefficiency in CACM has induced high costs for maintaining firmness and security of supply. As a result strong ***adverse incentives for the TSOs to underestimate available capacity*** to the market have been created, and consequently, the existing network capacity has been underutilised.

The approach for allocation of cross-border capacity differs between control areas (Member States) and methods and procedures are not coordinated. This ***lack of coordination in capacity allocation and congestion management*** results in a lack of efficiency in cross-border flows.

One of the key issues in considering the allocation of cross-border capacity is the anticipated increase in variable renewable and distributed generation and interconnection between national electricity markets. However, the ***applied methods for capacity calculation, allocation and congestion management do not sufficiently account for large-scale variable generation*** (e.g. taking into account loop flows, etc.)

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[7] Welfare being manifested in that the economically most efficient (cheapest) generators are always supplying the demand.

This means that generation and demand will become increasingly difficult to forecast at the day-ahead stage. As a result, the existing methods to calculate and allocate capacity and the organisation of wholesale markets will need to be developed further to meet this challenge. ***Intraday solutions to reflect the changes of variable generation closer to the real time are needed***.

2.3 Who is Affected, in what Ways, and to What Extent?

Market Participants

Whereas market participants (traders, power exchanges, market operators, brokers, etc.) conduct their operations within the existing framework and practical solutions for the CACM, the inadequacy and inefficiency of these solutions described in the previous chapter lead also to sub-optimal results of market participants' activities.

This leads on the one hand to reduced economic gain and profit for the market participants. On the other hand, this means also a sub-optimal overall system usage and not achieving the optimal possible welfare (i.e. not always having the most economically viable generation supplying the demand in the EU).

Transmission System Operators

For the TSOs, the adverse incentives to underestimate the interconnection capacity are not a sustainable approach. Moreover, even by "declaring" zero capacity, with inappropriate methods to manage CACM the loop-flows will still continue to endanger the operational security and at the same time the pressure from the market participants, from policy makers and regulators will grow further to provide proper support to the market and implement good, adequate CACM approaches.

Regulators / ACER / Member States

The national regulatory authorities (NRAs), ACER and Member States are charged with different aspects of legal provisions for the CACM according to the New Directive and the New Regulation. Moreover, the Existing CM Guidelines also stipulate a number of aspects which must – but without adequate CACM methods cannot – be fulfilled.

Customers and society

Finally, the most seriously affected actors and those who are the focus of all market activities are the customers. Reduced welfare directly reduces customers' benefits. Inappropriately dealing with e.g. loop-flows, variable generation integration, etc. increasingly affects the operational security of the networks, which also directly endangers the customers' interests for a secure and sustainable electricity supply. Moreover, not utilising the market potential to create true cross-border competition and failing to provide for effective and efficient CACM throughout the EU, does not just create conditions which are against the provisions of the European Treaty but also endangers the long-term industry and economy of Europe in the context of globalisation and global market competition for goods and services.

2.4 How should the Problem Evolve, all Things Being Equal? Should the EU Act?

Without action, the CACM problems identified above will increase in the future as systems become more interconnected, with more intensified load flows in the networks, with higher volatility and in general as market integration evolves and the interdependencies between the different control areas grow. Furthermore, growing intermittent generation will further increase the pressure and demand for an appropriate and well defined integration of such generation and, consequently, adequate capacity allocation and congestion management which will take due account of that.

Such a development antagonises the desired direction of striving to a better coordinated network development in Europe and better integration of the IEM. Supervision of such a development at European level will be nearly impossible. In addition, the spectrum of solutions to match the different requirements will need to broaden, resulting in higher costs for all parties concerned, including most notably the customers and then also society as a whole.

The goal should therefore be to create and implement an appropriate set of procedures and solutions that are transparent to everybody concerned with CACM and to which all parties can commit. This process shall help bring concerned parties together for a reasonable exchange because their points of discussion are understandable and their importance is clear. For that, the EU shall provide the framework and point out issues of particular interest.

In the process of developing a harmonised and well defined regime for capacity allocation and congestion management in the EU, the first positions on the vital topics of CACM should be addressed. Furthermore, positions on issues and topics interlinked with European rules of CACM should be communicated, in order to allow market participants and other actors to assess the relevant issue. Finally, any relevant work done previously should be taken into account.

3 OBJECTIVES OF THE EU INITIATIVE

3.1 General Objectives

To address the problems set out in the previous section, the overarching objective of the initiative towards the future CACM framework is to ensure optimal use of the transmission network for cross-border trade, in support of the creation of one truly integrated, competitive and efficient European Internal Electricity Market. This will result in the optimal operation and technical evolution of the European electric power system (network, generation, network users) through coordinated action from TSOs, market participants and actors.

This means further, that the future CACM framework should ensure the maximisation of trade value, leading to an efficient use of the generation system, limited only by the technical (security) constraints of the network.

In achieving this, the initiative will contribute to maintaining security of supply, supporting the completion and functioning of the internal market in electricity and cross-border trade, delivering benefits for the market participants and facilitating the fulfilment of the EU targets for the massive integration of variable renewable generation (wind).

Eventually, this will yield optimal welfare and benefits for the European customers and society as a whole.

The future framework for the CACM shall therefore establish objective, transparent, and non-discriminatory rules and regulations for all time frames, for all products and for all affected market participants and actors. It is within that scope that the EU TSOs, market participants, policy and law makers and regulators need to be obliged to implement the EU Target Model for CACM (Annex 4).

These overarching objectives will be delivered through a number of specific objectives focused on various elements of capacity allocation and congestion management.

3.2 Specific Objectives

<u>Objective #1: To ensure optimal use of transmission network capacity in a coordinated way</u>

The initiative aims to standardise the methods for:

i) coordinated capacity calculation,
ii) definition of zones for CACM.

Coordinated capacity calculation

The initiative aims to standardise the methods for the identification and utilisation of maximum available transmission network capacity within and between the EU control areas for the different time frames (daily, intraday and future / forward markets), in a ***coordinated*** way. Determining and allowing an optimal use of the transmission network capacity which can be used for trade at all time frames (daily, intraday, future / forward market) is an essential feature and one of the key steps for an effective and efficient CACM.

Definition of zones for CACM

The initiative aims further to address in an appropriate and ***coordinated*** manner the identification and definition of the zones (in or where applicable within) the EU control areas, between which the CACM methods and solutions should be applied. The identification and implementation of the zones is another essential feature and key step for an effective and efficient CACM.

Objective #2: To achieve reliable prices and liquidity in day-ahead capacity allocation

The rules and regulations of the future CACM framework should support the development of the internal market and fair competition, in terms of reliable, fair and competitive prices, clear price signals through the whole value chain and market liquidity in the day-ahead electricity market.

In order to achieve that, the access of market participants and actors to all relevant information necessary for efficient price formation and trade on a regional and European basis and for effective functioning of the market shall be ensured.

Considering that the day-ahead (spot) market is also a fundamental basis for the liquidity and proper functioning of the forward electricity market, achieving day-ahead market liquidity in a coordinated way and throughout all of the EU is one of the essential features and key specific objectives to be fulfilled.

Within this context, it is further important that the future CACM rules for the day-ahead capacity allocation account on one hand for the maximisation of trade opportunities and welfare and on the other for the support of operational security by the market operations.

To that end, the existing national market rules that require harmonisation shall be identified and adequate harmonisation methods and implementation developed, at the regional (where applicable), but even more (preferably) at the level of synchronous areas and of the whole of EU. It follows that the implementation of the CACM solutions for the day-ahead market should ensure future compatibility with the EU Target Model[8].

Coordination remains an essential aspect for the European TSOs, in developing and implementing adequate solutions for the day-ahead CACM and cross-border trade.

[8] The key elements of the EU Target Model for CACM are summarised in Annex 4.

Objective #3: To achieve efficient forward market

The rules and regulations of the future CACM framework should also ensure reliable, fair and competitive price signals and liquidity of the forward electricity market.

One important prerequisite for this is the liquidity and proper functioning of the day-ahead market in the EU. Moreover, access of market participants and actors to all relevant information necessary for efficient price formation and trade on a regional and European basis and for effective functioning of the market shall be ensured for the forward market as well.

Within this context it is further important that the future CACM rules for the forward electricity market take into account both the financial and physical products as applicable and foresee the methods for “reuse” and optimisation of those capacity which might be not needed by the market participants who have initially obtained them (e.g. adhering to the Use-It-Or-Sell-It principle).

The existing national market rules for the forward markets that require harmonisation shall be identified and adequate harmonisation methods and implementation developed at the regional and EU level. The implementation of the CACM solutions for the forward market should also ensure future compatibility with the EU Target Mod,el[9].

Coordination among the TSOs, PXs and other actors in charge of implementing the future CACM rules for the forward electricity markets remains an essential and key point.

Objective #4: To design efficient intraday market capacity allocation, in support of better trading opportunities, reduced balancing needs and effective integration of massive variable generation (wind)

The future CACM principles shall efficiently accommodate the expected increase of the short-term marginal cost and account for the hardly predictable variable generation, resulting in overall increased power flows over interconnections.

To achieve these objectives, the use of existing transmission infrastructure must be maximised and the market participants must be able to efficiently trade energy as close to real time as possible. Achieving efficient flows should eventually result in the most economically efficient generation and transmission choices to meet demand.

While designing and implementing the EU intraday market, besides ***coordination*** among all the actors involved (TSOs, PXs, etc.) it is essential that any adverse effects on other market time frames or products are avoided.

[9] The key elements of the EU Target Model for CACM are summarised in Annex 4.

4 POLICY OPTIONS AND THEIR ASSESSMENT

4.1 Policy Options and Delivery Mechanisms for achieving the Objectives

For each of the identified main problem areas that require action and in relation to the objectives defined in preceding chapters, the most suitable responses are described and assessed, thus proposing the preferred alternative.

From a high level perspective, strategies range from a so-called "Option 0" (i.e. status quo is maintained with no action at the EU level) to a comprehensive compound of framework guidelines and binding network codes at EU level; and in between, a national and regional scope is also deemed possible: different problems may call for different approaches.

The way a certain option is put into effect relies on a number of dimensions to be considered regarding policy assessment. Different combinations of mechanisms can be considered alongside a particular policy option to achieve the final result; the impact assessment should underline where a determined mechanism would have a significant role in driving a policy option's impact.

It is also worth highlighting that:

- Network codes to be prepared by the ENTSO for Electricity are not intended to replace the necessary national network codes for non-cross-border issues[10];
- Network codes shall further focus mainly on the cross-border, IEM related and market integration issues and shall be without prejudice to the Member States' right to establish national network codes which do not affect cross-border trade[11].

4.2 Evaluation Criteria and Main Stakeholders

According to the Commission's IA guidelines [1], the screening process should consider the main policy options and then eliminate the not-applicable ones immediately.

Moreover, for the policies considered (including also *Option 0*), it is important to consider all the relevant positive and negative impacts alongside each other, regardless of whether they are expressed in qualitative, quantitative or monetary terms.

Thus, a screening process allows obtaining a short list of the most promising option(s) whose impacts can be further analysed. Policy options are gauged for their suitability in meeting objectives of each area against these three high level criteria:

[10] Article 7 of Regulation (EC) No 714/2009

[11] Article 8.7 of Regulation (EC) No 714/2009

- **Effectiveness**: The extent to which options can be expected to achieve the objectives of the proposal;

- **Efficiency**: The extent to which options can be expected to achieve the objectives for a given level of resources with least cost and highest benefit (cost-effectiveness); and

- **Consistency**: The extent to which options are likely (not) to limit trade-offs across the economic, social and environmental domain.

Policy options scoring high in the screening process are subject to a cost-benefit analysis for diverse parties affected, based on discussions and findings from the different references listed in Annex 3. Although a quantitative approach is not straightforward at this stage, a differentiated view on all influencing and influenced factors is provided.

Beyond the above mentioned three key criteria, the following additional criteria have been applied where necessary, for the quantification of the outcome of the different policy options. (Not all these criteria are simultaneously used for the assessment of all policy options.)

- **Competition:** The CACM framework shall ensure that congestion management is tackled on the basis of market-based mechanisms, promoting competition in generation, wholesale trade and at retail level. Any market segmentation and niche effects shall be avoided. Competition aspects are also relevant for defining and sharing available transmission capacity between different control areas or zones. A market-based approach implies that the market participants (through offers/bids) should decide which transaction has to be made on the basis of information such as price signals.

- **Long-term and operational system security**: Providing short and long-term security of the electricity power system are possibly less a criteria than a prerequisite for each of the policy options.

  Nevertheless, selected policy options should allow an efficient assessment of the operational system security, and in particular of the limitation of the transmission system. However it is important to consider that maximising available capacity and the design and impacts of different policy options may lead to a trade-off between enabling markets and competition vs. system security.

  Additionally, the influence of an increased share of variable generation may have a different impact for different policy options which will need to be considered when assessing the policy options. Thus, system security is included as one criterion.

- **Non-Discrimination:** Selected policy options shall not discriminate between different types of transactions. In particular, no discrimination should be made between transactions of different market participants, between short and long-term transactions or between internal and cross-border exchanges.

- **Sustainability**: Proposed policy options should allow and facilitate the implementation of the European climate policy goals, and in particular facilitate the integration of renewables allowing at the same time as efficient use of the transmission system only limited by system security constraints.

- **Technical feasibility**: The selected policy options should be technically feasible in a reasonable period of time, and this feasibility should extend to the fulfillment of the other selection criteria. Nevertheless, if feasibility turns out to be impossible in the foreseen time frame, a deployment path, including further steps, needs to be planned.

- **Transparency**: Transparency is a key measure to ensure non-discrimination by providing equal information to all market players, but is also key for the proper understanding of market and price formation processes.

  The selected policy options should be fully transparent to market players. In particular, the chosen options should be easy to understand and give predicable results; they should not be perceived as a kind of “black box” by market participants.

  In addition, the selected policy option should allow the publication of efficient price signals.

Main stakeholder groups considered in this IIA are:

- **Transmission System Operators**

- **Market participants** (traders, generators, brokers, etc.)

- **Power Exchanges** (organised electricity markets)

- **Market operators** (where applicable also clearing & settlement agents)

- **Policy and law makers in the EU and in Member States**

- **Regulators** (NRAs and ACER in the future)

4.3 Assessment of Impacts

An initial impact assessment of policy options by action area and associated delivery mechanisms aims at clarifying the probability of achieving the identified objectives, i.e. the likelihood of solving problems previously detected, given a number of underlying problems. It helps to predict consequences of policies, too – both intended and unintended.

This exercise allows for gathering information about likely impacts on stakeholders against the three main criteria and the additional criteria above, as well as potential trade-offs and synergies. It is also useful to identify enhancing measures, i.e. the ways to ‘fine-tune’ a policy option.

4.4 Policy Options and Delivery Mechanisms for achieving the Objectives

In the following section, different policy options and related delivery mechanisms are assessed in terms of their suitability to reach the objectives defined in Chapter 3, which in turn are required to resolve of problems identified in Chapter 2.

4.4.1 Objective #1-1: To Ensure Optimal Use of Transmission Network Capacity in a Coordinated Way – Capacity Calculation

4.4.1.1 What is the issue?

Capacity calculation is one of the key, technically most challenging elements of the capacity allocation and congestion management for electricity.

It is worth mentioning that in some countries, despite transmission network reinforcements, proposed commercial cross-border capacity have been reduced or have not increased as was expected.

In 2000 and 2001, ETSO published several documents[12] on the calculation of cross-border capacity based on the “”ATC” (Available Transfer Capacity) method, as it is called today.

With growing electricity exchanges in and between the control areas of the EU Member States and with the massive deployment of variable generation (wind), other approaches to capacity calculation, capable of better accounting for the loop-flows in meshed transmission networks (e.g. flow-based calculation) have been considered and are in some cases being implemented. Whereas there are indications that e.g. in the meshed transmission networks of continental Europe, flow-based calculation would deliver better results, more capacity and operational security [2], no implementation of flow-based capacity calculation has been completed until now (September 2010).

In particular, the issue of the sharing of the available transmission capacity on several interconnections with a significant mutual influence between them has not been addressed appropriately yet. This issue is of particular importance for the implementation of implicit auctions (market coupling/splitting projects) in order to avoid potential discrimination between the interconnections.

The general goal here should be to reduce the arbitrary assumptions related to system security made in capacity calculations and to move towards a more market-based definition of transmission capacity.

[12] http://www.entsoe.eu/fileadmin/user_upload/_library/ntc/entsoe_transferCapacityDefinitions.pdf
http://www.entsoe.eu/fileadmin/user_upload/_library/ntc/entsoe_NTCusersInformation.pdf

It is important to realise that capacity calculation is a cross-cutting issue, affecting the whole CACM design and it needs a consistent approach across all time frames.

Indeed, the existing and new (3rd Package) legal requirements of relevance for the coordinated capacity allocation (summarised in Annex 5.1) stipulate that:

> *"… With a view to promoting fair and efficient competition and cross-border trade, coordination between TSOs within the regions … shall include all the steps from capacity calculation and optimisation of allocation to secure operation of the network, with clear assignments of responsibility. Such coordination shall include, in particular: the use of a common transmission model dealing efficiently with interdependent physical loop-flows and having regard to discrepancies between physical and commercial flows …"*

These provisions, experiences and lessons learned so far in the different CACM projects and capacity calculation discussions in the EU ERI (Electricity Regional Initiatives) have been a subject of intensive discussions in the Project Coordination Group and resulted in the key elements of the EU Target Model for CACM (Annex 4).

4.4.1.2 What are the policy options? What is their impact?

1.A. No action on coordinated capacity calculation (*Option 0*).

Recalling the problem identification in Chapter 2 and the definition of general and specific objectives in Chapter 3, it follows that without enhancement of the capacity calculation method, the objectives of the future CACM will not be reached.

Moreover, considering the three key criteria according to which the policy options need to be assessed yields also that the *Option 0* is not an acceptable one: neither the effectiveness (achieving the objectives set), nor the benefits (for the market participants, TSOs, customers and society as a whole), nor a consistency in terms of trade-off between economic, social and environmental domain can be achieved by retaining the status-quo of capacity calculation as it is today.

Moreover, by considering additional criteria which are particularly relevant for capacity calculation (long-term and operational security, sustainability in terms of efficient use of transmission network only limited by real security constraints and technical feasibility), the *Option 0* is clearly not the appropriate one.

It follows that *Option 0* is not the right policy option and that no action at EU level will lead to deteriorated situation in terms of capacity calculation in the future. *Option 0* is therefore not considered appropriate for capacity calculation.

1.B. Agreed capacity

This policy option means that an agreement between neighbouring TSOs determines the availability of capacity on the interconnection. This approach is in use between some Member States, however it is not analysed further, because it is both not compliant with the existing and legal provisions (Annex 5.1) and not meeting the criteria for evaluation of policy options defined before.

1.C. Available Transmission Capacity (ATC) Method

1.C.1 Description of the Policy Option

This policy option means that the capacity is calculated by using an approach set out by ETSO in 2001 (described in Annex 5.2). It defines the ex-ante Net Transfer Capacity (NTC) over a single boundary as a function of Total Transfer Capacity (TTC) less a Transmission Reliability margin (TRM).

1.C.2 Real Life Examples of the Policy Option

Bilaterally coordinated ATC is the most commonly applied capacity calculation method across the EU today.

1.C.3 Assessment of the Policy Option

For the assessment of this policy option, it is important to distinguish the case of heavily meshed transmission networks, where interconnections have a significant mutual influence between them, from cases corresponding to simpler network structures with a lower degree of "meshedness".

ATC has laid down the basis for the development of cross-border trade since the beginning of liberalisation. For simple cases, where the simplicity of the method and its general acceptance are important, this method provides benefits for the development of cross-border trade.

In particular, in the absence of heavily meshed networks and in the absence of a significant influence of a border on other borders, this method should still constitute a possible choice for short term capacity calculation and could be considered as broadly meeting the three key criteria defined for the evaluation of policy options: effectiveness, efficiency and consistency.

However, the limitations of this policy option are obvious in case of meshed networks and the need to coordinate the calculations between all the TSOs (control areas) affected at the regional level or even beyond it.

Already identified since 2001, some of the limitations of the ATC method linked to the "Parallel Flow" phenomena are clearly indicated in section 4 of the ETSO document [3]. The interdependencies of NTC values between pairs of control areas in meshed networks systems are clearly identified.

It is also clearly indicated in [3] that "***NTC values itself do not provide the basis of a co-ordinated method of allocating cross-border trade over several borders in a meshed network***".

Finally, concerning the importance of NTC calculations, a premonitory statement was made in [3]: "***Therefore, the importance that NTC values actually have in the transaction based concepts of the international trade in Continental Europe will diminish***".

If applied to more complex cases with meshed networks and strong interdependency between the involved interconnections, ATC may introduce discrimination – violating thus one of the additional criteria defined for policy options assessment - between internal and cross-border exchanges and between the control area (national) borders.

Furthermore, for a practical reference, it is useful to observe the discussions and work on capacity calculation in the two European regions which are characterised by highly meshed networks and interdependencies between the interconnections.

CWE Region

> In January 2009, in the scope of the work on the implementation of a flow-based market coupling in the CWE Region, CWE TSOs and Regulators made a "Common communication"[13] where they indicate that: *"The first option corresponds to the currently applied practice of bilateral ATC calculation. Stricto sensu, the calculated capacity is only valid for exchanges on the corresponding border, and any exchanges beyond the considered market hypothesis may put network security at risk. Therefore, specific security margins (e.g. addressing potential loop flows) are applied to ensure that network security is safeguarded. The optimal use of offered capacity which is determined as a result of the market coupling algorithm might lead to unforeseen/unseen stressed situations which this method may not be able to address efficiently."*

CEE Region

> Following initial discussions and the setting of priorities for the CEE Region work and based on the results of a detailed analysis and comparison of the ATC method with other methods in [2], the CEE Regulators have stated[14]: "*CEE Regulators confirm their support for the FBA project and objectives and request the CEE TSOs to proceed with the rapid development and testing of the FBA system*.

As indicated, the ATC method was only targeted by the TSOs for bilateral calculations in non-meshed networks. Its main drawbacks if it is applied to more complex situations are a poor assessment of system security (the use of arbitrary security margins) and its inability to define capacity on interdependent borders.

It should also be indicated that this method has to cope with a major contradiction, linked to the circular nature of capacity calculation: generation schedules are necessary for the determination of transmission capacity, which are used for the fixing of generation schedules.

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[13] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/Central-West/Meetings1/RCC_meetings/14supthsup%20CW%20RCC/DD/common%20communication%20to%20SG1%20050209%20_3_.pdf

[14] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/Central-East/Meetings1/IG_meetings/15supthsup%20CEE%20IG/AD/statement_fba_regulators_080924_FINAL_CLEAN.pdf

Nevertheless, for less meshed networks ATC-based methods still have the advantage of simplicity, robustness and transparency.

1.D. Coordinated ATC Capacity Calculation

1.D.1 Description of the Policy Option

This method takes the ATC approach and attempts to coordinate capacity calculation across several borders (in a country or across a region) with significant influence over each other. The elaboration of a common grid model (which is a merger of national or control area base cases) across control areas (MS) affected is a key component of this approach.

With the implementation of coordinated implicit auctions (market coupling and/or market splitting) at regional level, the need for a coordinated capacity calculation method becomes more and more evident, especially in continental Europe (regions CWE and CEE) where the networks are heavily meshed and the interdependencies between the interconnections high.

The Coordinated ATC Method is based on the coordinated application of the ATC Method for the determination of capacity on borders which have a significant influence on each other.

Here, coordination means encompassing at least several borders of several countries or across a region. The goal is to find a capacity calculation method suitable for sharing (allocation) available transmission capacity on different borders that have a significant influence between them, in a non-arbitrary way. More precisely, the key question here is the sharing, and very often the reservation, of the transmission margin available on a particular network element for coupled interconnections.

In the day-ahead time frame, and having in mind coordinated auctions or market coupling, the objective of a determination of cross-border transmission capacity inside a region in the day-ahead time frame is to find ex-ante a set of firm cross-border (cross-zonal) capacity that ensure a safe operation of the system.

1.D.2 Real Life Examples of the Policy Option

No known example of this method has been implemented yet[15]. Nevertheless, it is important at this stage to clearly indicate the reasons for the difficulties linked with this approach.

[15] It is worth mentioning that in the CWE region, the implementation of the CWE market coupling is based on existing methods (bilateral capacity calculations and agreements) combined with a coordinated security assessment that may however lead to a coordinated reduction (instead of optimisation) of capacity proposed bilaterally.

1.D.3 Assessment of the Policy Option

The main challenge of this approach lies in the ex-ante calculation of transmission capacity and in the search for a set of a few transmission capacity values between countries (zones) such that the flows in several hundred physical lines of the system do not exceed its maximum technical capacity (in N and N-1 situations) for all possible exchanges in and between the PXs of the involved countries or zones. Indeed, this might prove to be an impossible mathematical task.

Furthermore, an ex-ante determination of the sharing of the transmission capacity on several cross-border (cross-zonal) interconnections is not able to take into account the value of this capacity for the market. In other words, this way of sharing capacity between borders may have difficulties in being market-based.

Recent work in the development of the day-ahead market has clearly confirmed these difficulties. In a recent common communication, CWE TSOs and regulators indicated[16]: *"The second option corresponds to a fully coordinated and automatic calculation of cross-border capacity based on the same ATC concept. TSOs indicated that the difficulties encountered in the development of coordinated ATC calculations were one of the reasons for switching, a few years ago, to flow-based approaches. From a theoretical and practical point of view,* ***it seems impossible to set up a coordinated and automatic ATC calculation method that, at the same time, fully ensures network security and provides an efficient use of the technical capability of the transmission system****."*

In other words, Coordinated and automatic ATC – if it is implemented for short term capacity calculation, which has not been the case so far – will in the meshed networks with high dependency of interconnections lead to very low cross-border (cross-zonal) capacity. Moreover, it will also provide a poor estimation of the operational security.

The elaboration of the starting point of the transmission capacity calculation process, also called a ***base case***, is one of the weak elements of the Coordinated ATC Method.

The objective of such a base case is the determination of the physical flows pre-existing for the allocation process by "removing" some exchanges from the common snapshot (example: snapshot that may be obtained on the basis of the Day-ahead Congestion Forecast - DACF - calculations). This concept builds on the assumption that it is possible to separate all exchanges into two groups such as daily cross-border exchanges and other exchanges, or internal and cross-border exchanges. However, very often, these exchanges correspond to cross-border exchanges and

[16] See the common publication made by the CWE Regulators and the TSOs of the CW region published on ERGEG CW region website as a distributed document of the 14th RCC: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/Central-West/Meetings1/RCC_meetings/14supthsup%20CW%20RCC/DD/common%20communication%20to%20SG1%20050209%20_3_.pdf

the method gives priority implicitly to internal exchanges over cross-border exchanges.

In the sharing of transmission capacity on different borders, there is a further risk that transmission capacity “reserved” for one border may come at the detriment of other borders.

In addition to the risk of discrimination between different types of exchanges, this approach has a more serious flaw linked to the construction of a base case, as explained in Annex 5.3. Following the analysis in Annex 5.3 and especially evaluating this policy option in term of the three basic criteria – effectiveness, efficiency and consistency – it follows that the Coordinated ATC Method is not practically feasible for short term capacity calculation. It may further induce discrimination and it cannot share transmission capacity between interdependent borders in a market-based way and, resulting “artificially” in very low capacity, is unable to maximise network use, or to fully use network capabilities while ensuring system security.

This means also that the Coordinated ATC Method is not in line with the legal provisions for capacity calculation (Annex 5.1). It follows hence that this policy option is not considered appropriate for resolving the CACM problems identified in Chapter 2 and for delivering the objectives described in Chapter 3.

1.E. Flow-Based Capacity Calculation

1.E.1 Description of the Policy Option

The flow-based capacity calculation method uses a common grid model to assess physical network flows (not just transmission capacity between areas), enabling a calculation of Available Maximum Flows (AMF, the concept developed and introduced in the CEE region project on coordinated flow-based capacity calculation) on predefined “critical elements” on the network. The approach derives capacity ex-post, on clearing of the day-ahead market, and calculates network flows simultaneously with price.

This option contains a significant change compared with the other methods, since no ex-ante firm/fixed transmission capacity values between countries/zones are calculated and announced to the market for allocation.

Instead, the Available Maximum Flows (AMF) at pre-defined critical elements in the network are the relevant figures to assess whether a transaction can take place or not. AMF are calculated on the basis of a base case, which may introduce the problem described in the latter subsection on coordinated ATC.

With this method, system security requirements are taken into account at the allocation stage, by constraining flows in these pre-defined critical network elements on the basis of the laws of physics applicable to meshed networks (Kirchhoff laws). This system security check is no longer based on the worst case scenario considering the simultaneous occurrence of all offered commercial capacity. Whereas the concept as such is not a novel approach (it builds upon a simplified load-flow calculation algorithm and yields the dependencies between the nodes-branches), it offers some interesting features in comparison with other capacity calculation methods discussed before.

The first reference to this method was made in 2004 by ETSO[17], where the following general description is given: *"The first and most general is the Co-ordinated Congestion Management scheme proposed by ETSO which is a practical application of explicit or implicit allocations simultaneously on many interconnections while respecting the effects of loop flows. The assessment of network security limits before energy market clearing is done in terms of physical flow margins and not in terms of ATC. CCM avoids contract path bias. If the network is modeled in detail, it also avoids the need to assume future market conditions when specifying transmission capacity"*.

The way network constraints are taken into account differs significantly with the different application of this method, from a very coarse security check, such as in market coupling (corresponding to bottleneck capacity "BC" of the 2004 ETSO terminology[18]) and implicit auctions, towards a more refined approach like the one under investigation in the CWE region with critical branches "CB" in N and N-1 situations[19] or a detailed and comprehensive approach in the CEE region's project for coordinated flow-based capacity calculation with critical elements.

In a flow-based capacity calculation, relevant physical properties of the transmission network are taken into account, contrary to just the transmission capacity between "areas" as in the NTC approach.

Incorporating a flow-based calculation in an implicit day-ahead capacity allocation means that transmission capacity (TC) price, energy price and flow are determined simultaneously within the same algorithm, taking into account operational security constraints adapted to meshed network situations.

This makes redundant the (problematic) arbitrary sharing of transmission capacity between borders executed by the TSOs with the (Bilateral or Coordinated) ATC Method.

The quantity of electric power that can be transmitted between different control areas (or zones within the control areas, if applicable) is determined simultaneously with the prices. This leads both to a better utilisation of the transmission network and to the better price signals for generation and consumption, supporting thus the achievement of one of the key objectives identified in Chapter 3.

17 http://www.entsoe.eu/fileadmin/user_upload/_library/publications/etso/Congestion_Management/Current_CM_methods_final_20040908.pdf

18 http://www.entsoe.eu/fileadmin/user_upload/_library/publications/etso/Congestion_Management/ETSO-EuroPEX_Interimreport_Sept-2004-.pdf

19 "Critical Branches" or "Critical Elements" correspond to the "Flowgate" concept in North American terminology.

Flow-based short term capacity calculation with a sufficiently detailed grid model will allow a higher utilisation of the network. To maximise the benefits of such a model, an adequate definition of bidding zones is necessary.

1.E.2 Real Life Examples of the Policy Option

A significant effort has been invested by the CEE and CWE regions, towards designing and implementing flow-based calculation. It is anticipated that the results of work and practical implementation, which were initiated in the CEE region in 2006, may be “transferred” and “reused” in the CWE and possibly other EU regions where the transmission networks are meshed and the degree of interdependency between the interconnections high.

1.E.3 Assessment of the Policy Option

The flow-based approach constitutes a market-based answer to the question of the prioritisation of exchanges across borders/zones with significant mutual influence. This approach avoids the calculation of artificial, static values for the transmission capacity. The FB algorithm allows the maximisation of the value (in terms of cleared bids) of the transmission system, taking into account explicitly the security of the system through network transmission constraints and N-1 situations.

In addition, the problem linked to existing and new DC cross-regional interconnections should not be underestimated. One of the objectives of capacity calculation within the whole CACM concept is to be able to provide transmission capacity also for these interconnections in a non-discriminatory and market-based way. Only a flow-based approach seems to be applicable for those cases, combined with redispatching arrangements between non-integrated areas.

In general, the flow-based short term capacity calculation, as described here, should lead to less discrimination between borders than the other options mentioned. The flow and transmission capacity are determined simultaneously with prices, based on the information about consumption and production inherent in the bids and a detailed grid model. With a well functioning optimisation routine, this should lead to optimal (and thus non-discriminating) capacity between all market areas.

In the case of heavily meshed networks, this policy option seems to show advantages compared to an automatic Coordinated ATC approach in terms of feasibility, system security appraisal and efficiency.

All consequences of this solution for capacity calculation were not considered in detail in the PCG work on the day-ahead market. In particular, the negative impact of flow-based allocation on the quality of price signals of smaller PXs and the need to have an appropriate definition of zones (addressed in the subsequent chapter) were not discussed. It is worth noting that this method has also not yet delivered satisfactory results in the heavily meshed network of the continental part of Europe, but that a number of practical results of testing, implementation and studies, most notably in the CEE region [2] are expected to deliver significant improvements during 2010.

By evaluating this policy option against the defined key criteria (effectiveness, efficiency and consistency), but also by considering it in light of the additional criteria of particular relevance for capacity calculation (long-term and operational security, sustainability in terms of considering loop-flows and technical feasibility), the policy option of flow-based short term capacity calculation is considered as providing the best approach for the control areas and zones where transmission networks are highly meshed and the interdependencies between the interconnections high.

1.F. Nodal Approach

1.F.1 Description of the Policy Option

Closely related and actually based on the flow-based approach, the nodal approach calculates capacity availability and congestion on the basis of individual nodes in the network, i.e. there is no simplification of the network into critical elements or zones.

This approach may be seen as an evolution of the flow-based calculation scheme where all network constraints are taken into account at the allocation stage.

It is important to indicate that "nodal" refers to congestion management and pricing and does not prevent the creation of liquid hub prices (i.e. groups of nodes) serving as a reference for forward markets and if required the implementation of a uniform (end)-consumers price per country (based on a weighted average of hourly nodal prices).

Unlike the other capacity calculation methods described in this paper, this method can also be seen as a congestion management method supporting (re)dispatching, since all available generation units (and controllable load, if any) are used in the management of congestion.

Again, as in the flow-based method, no ex-ante capacity is calculated and proposed to market players before the clearing of the day-ahead market. The necessary ex-ante transparency for market players is mainly constituted by the availability of generation units, consumption forecast and the availability of all transmission elements.

In the PCG work, this option was introduced as a way to solve the "chicken and egg problem" (referenced also as the circular problem in this IIA), constituted by the paradox of the need for exact information of the unit generation level for the determination of transmission capacity which is used by market players for the determination of generation output levels. Indeed, no capacity is calculated before the clearing of the day-ahead market. Instead, the clearing mechanism uses the locational information provided by market players on their willingness to participate in the day-ahead market reflected in their bids/offers.

This congestion management method is very often described as the ***bid based security constrained, non obligatory, economic dispatch***.

"***Bid based***" indicates that this system is based on offers (for injection or generation) and bids (for demand or consumption) which indicate the readiness (firm commitment) of market players to participate in the market at a given price and for a given volume.

"***Security constrained***" means that the security of the system is taken into account directly at the allocation process through constraints corresponding to network and generation elements in N and N-1 conditions.

"***Non-obligatory***" indicates that market players are not obliged to participate in the mechanism, but in this case lose the opportunity of influencing (fixing) the locational price and the corresponding congestion charges, if any, that they are obliged to pay for transferring electricity. "***Delivering locational prices***" means that the congestion mechanism provides prices for each location (node) allowing the pricing of congestion.

"***Economic dispatch***" means that the related congestion management is based on the optimisation (minimisation) of dispatching (and redispatching) costs. It is the (centralised) system that fixes generation output level on the basis of offers and bids of generators/consumers.

Finally, it should be recalled that the last model constitutes the market-based version of the Optimum Power Flows (OPF) calculations which were used commonly before liberalisation, by the vertically integrated utilities, on the basis of variable costs of generation units. Whereas the OPF calculations were able to minimise the costs of electrical losses in the past, the Nodal Approach would be able to contribute to minimisation of costs of electrical losses where applied in the future.

To be clear, with this policy option, no ex-ante capacity is calculated, the determination of a base case is no longer required (and the difficulties linked to its determination disappear), and all long-term transmission rights are re-circulated in the day-ahead clearing mechanism as financial commitments.

1.F.2 Real Life Examples of the Policy Option

Several applications of this method exist worldwide: in North America (PJM Interconnection, ISO New England, California ISO, etc.) and in other countries like New Zealand.

1.F.3 Assessment of the Policy Option

This method aims at the creation of integrated markets and removes all artificial barriers (like political borders) inside the area. Concerning capacity calculation, and in the absence of ex-ante determination of transmission capacity, this congestion management method is straightforward.

This method further allows an efficient use of the transmission network, well suited for large heavily meshed areas and it does not require arbitrary security margins. Nevertheless, the implementation of this method requires numerous changes in the current market design which may be more costly to implement. At the same time, however, expected welfare benefits of this policy option compared to FB MC are higher by an order of magnitude.

In addition, the compatibility of this method with low-flexibility generation parks (nuclear, coal, etc.) should be studied in more detail.

The Nodal Approach Method seems to correspond to the defined key criteria (effectiveness, efficiency and consistency) and to a number of additional criteria relevant for capacity calculation – although further studies concentrating on the European surroundings are still needed. Moreover, this method is in the long run clearly feasible and applicable to large meshed areas (as has been proven in the real life applications mentioned above). However, introducing a Nodal Approach in Europe would require substantial changes, not just in present market design of CACM but also in the legal provisions which are currently building upon the 3rd Package. This means that the Nodal Approach itself corresponds well to the legal provisions for capacity calculation (Annex 5.1) but in order to have it implemented in an efficient and effective way, a number of additional provisions and obligations would have to be defined additionally, for all affected actors: TSOs, market participants, law and policy makers, regulators, etc.

It is therefore important to consider the Nodal Approach as the ultimate goal and (technically and economically) optimal solution for capacity calculation within CACM for the future, but at the same time to pursue the practical development and implementation based on the flow-based calculation.

4.4.1.3 Conclusions and Preferred Policy Options for Capacity Calculation

Capacity calculation shall be based on compatible and transparent principles across control area (and zone) borders. The selected methods shall allow TSOs to maximise capacity to the market while at the same time taking into account the given security constraints of the network.

A problem to be tackled is TSOs' tendency to underestimate available capacity, due to the uncertainty in forecasting load flow in the network. This is in part due to the difficulty in forecasting location of supply and demand, i.e. accurate load flows prior to commercial bids to the market, but also due to different calculation procedures and a lack of transparency in methods and data across borders.

A common coordinated flow-based approach to short term capacity calculation offers the scope to solve this problem to a large extent.

The first step to be achieved is a common European grid model, which allows for load flow forecast. The model shall be based on common data and processes, allowing for coordination and a security checked optimisation of available capacity. Such a model would increase TSO confidence in estimating available capacity. Particular attention should be given to the process of elaborating of the common base case in other to avoid possible discrimination between internal and cross-border exchanges.

The Nodal Approach Method has been considered as a theoretical optimum, given e.g. that it would entail a simultaneous setting of price and load. However, the Nodal Approach requires radical changes for its implementation and therefore corresponding practical implications for Europe, and an assessment of cost/benefits, would have to be studied in more detail before it could be considered.

*The **Flow-Based Method*** for capacity calculation makes use of locational information in the grid model, and thus allows for a more optimal calculation of load flow and thus utilisation of the network. This method is therefore considered to be the best one for short term capacity calculation in cases where transmission networks are meshed and interdependencies between the interconnections are high (e.g. ENTSO-E Continental Europe, most notably the regions CWE and CEE).

ATC (bilateral) is considered a feasible method for short term capacity calculation in less meshed networks, such as the Nordic power system or possibly the cases of interconnections between the large peninsulas or islands in Europe. However, this method must be applied with due caution as it is essential to ensure that the trade of electricity within one control area is managed in order to minimise any adverse impacts on neighbouring control areas (countries).

In both cases, long-term calculation methodologies shall be fully compatible with the short term capacity calculation, take into account the actual impact of commercial transactions on the physical grid situation and the fact that basic input data only has limited reliability because of changing market situations.

The definition of zones, which is dealt with in the following section, is closely related to the capacity calculation and selection of the appropriate policy option for that.

4.4.2 Objective #1-2: To Ensure Optimal Use of Transmission Network Capacity in a Coordinated Way – Definition of Zones for CACM

4.4.2.1 What is the issue?

A market can be divided into several zones according to e.g. national borders and/or network topology. A zone is commonly understood as an area with reduced internal congestion (emulating a “copper plate”) that is managed by redispatching /countertrade.

With implicit auctions, “zone” can refer to a bidding area or a price area or both. A bidding area may become a price area when the network between areas is congested. This method (of congestion management) is known as market splitting and is applied in the Nordic market.

It is also possible to aggregate bidding areas into one price zone, as is done in Italy, which is divided into six bidding areas[20], but with uniform pricing[21] on the demand side (i.e. the demand price is the average of the zonal prices weighed on the zonal consumptions).

Today, in Europe zones correspond in most cases to the control areas boundaries, which do not always reflect the network topology.

[20] More specifically, the matching algorithm of the Italian market takes into account the aforementioned six bidding zones and also six injections points (: Monfalcone, Priolo, Foggia, Brindisi, Rossano and Corsica. Therefore there are actually up to 12 different zonal prices taken into account.

[21] The price policy to consumers is outside the remit of this report, so unless otherwise mentioned “prices” refer to wholesale prices.

In this IIA, the term “zone”, unless otherwise noted, means bidding zone. Market players’ bids are tagged in accordance with the zone within which they are located. Structural congestion refers to congestion that is of a certain volume and duration i.e. they arise with regularity under certain conditions when the desired transfer of electricity from producers to consumers exceeds the capacity of the transmission network. Finally, critical elements or critical branches (CB) of FB methods constitute predefined network elements where congestion is likely to appear.

In summary, while it is desirable to have bidding zones as large as possible for the sake of market liquidity, number of market participants and overall welfare increase for the affected customers, it needs to be carefully considered where the actual, physical borders (i.e. physical bottlenecks in the transmission networks) lie, in order to establish the system of the zonal borders vs. control area borders (and thus to optimise welfare). In that context, there are no universal solutions and any final approaches will need to take into account the national and regional specificities.

Market Power, TSOs and Discrimination

Delimitation of zones may have negative effects on the functioning of the market in other zones. In particular, important redispatching / countertrade actions may have as a consequence that neighbour TSOs may have to reduce commercial transmission capacity by an artificially high, not economically justified security margin for unexpected flows. This may also discriminate market players of the affected zone.

Redispatching and Countertrade

Principles used for the delimitation of zones have a significant impact on the volume of redispatching actions required to manage congestion and to ensure network security.

Main options related to the delimitation of zones have the following consequences in terms of redispatching. In the uniform system, where only one area covers the whole (European) system and where no transmission capacity limit is defined inside the area, all congestion is managed ex-post (after their detection during a security assessment based on nominations) by redispatching / countertrade. In the zonal system, where capacity is defined between zones, congestion is solved using market splitting, and if there is internal congestion within a zone after market clearing, this is handled with redispatching / countertrade.

In a nodal system, where the exact transmission capacity limitations are taken into account at the allocation stage, the need for redispatching / countertrade is non-existent or very limited since congestion is managed in the market clearing.

It is important to emphasise that the incorporation of a flow optimisation model in the capacity calculation process would enable better appraisal of transmission network constraints, and thus greatly reduce the need for redispatching actions by the TSO.

In this Initial Impact Assessment, the term “structural redispatching” will be used precisely for these redispatching actions linked to an inaccurate appraisal of network constraints at the allocation/clearing time. These redispatching actions are necessary even without the occurrence of a new event like a change of consumption level, the tripping of a generation unit or a deviation of wind conditions from expectations. These redispatching actions correspond to electricity to be delivered the following day and, apart from a delay of a few hours for the assessment of system security, concern the same product as the day-ahead market, where electricity is traded in day-ahead for the different hours of the following day. With a more accurate representation of the network, these "structural" redispatching actions could be managed together with the day-ahead market, avoiding expensive redispatching closer to real time and socialised on network users. Therefore, these "structural" redispatching actions should be managed together with the day-ahead market, in order to avoid market segmentation issues and promote competition. In other words, congestion should, as far as possible, be made visible and be managed in the day-ahead time frame through a zonal division of the market.

Capacity Calculation and Market Efficiency

Inadequate zone delimitations and inefficient capacity calculation methods may lead to displacement of congestion internal to a zone towards the borders of the zone, which in turn affects the functioning of the internal market.

Price Signals

The short-term market value of electricity depends on marginal production costs, the willingness to pay of consumers, as well as modalities in the network, in particular the cost of losses and the shadow price of network capacity (in the case of congestion).

Thus, an "incorrect" zonal division of the market leads to inefficiencies in terms of the system in general and congestion management in particular. The inefficiencies relate to costs of redispatching, utilisation of network and generation resources, and the ability of the system to yield correct prices to the market.

Indeed, the relevance of a price signal in day-ahead may be questioned if large amounts of redispatching costs are necessary to ensure system security and if these redispatching costs are socialised on all network users and not charged to those who are responsible for it. Moreover, an EU-wide uniform method for the sharing of redispatching costs between TSOs has not been defined yet.

If the zones resulting from the division of the network based on its topology are considered too small to ensure liquidity, nothing prevents the creation of liquid hub made up of several zones.

Finally, if the final objective is the creation of the internal market covering the whole of Europe, the impact of electricity losses on prices may become significant and as long as prices are not based on network losses and scarcity of capacity, prices will give wrong signals about the value of electricity.

Abuse of Market Power

The definition of zones may have an impact on the number of actors within that zone, e.g. a small zone will typically have fewer actors than a large zone; thus raising the issue of market power. However, depending on the present market design, the market power situation as such does not necessarily change with zone size, as it is triggered by the congested network.

In an efficiently defined zonal system, the congestion will be managed in the day-ahead time frame through market splitting, as opposed to being handled in the balancing time frame through redispatching. This will shift the potential for abusing a dominant market position from the balancing (redispatching) time frame to the day-ahead time frame. Given that the day-ahead time frame has higher volume and liquidity (ref. target model for day-ahead), any issues of market power can be more easily identified and dealt with.

It is sometimes argued that when evaluating market power combined with the issue of zone size, it is necessary to differentiate between market-based and cost-based redispatching. In the case of market-based redispatching, there is a risk that a producer within a regularly congested network area will be the only one able to offer redispatching services, which implies that it will set the price. In case of cost-based redispatch, the same producer should not be able to abuse its market power as its profit is not influenced by its powerful position. As the actual bids need to be cost-based, an adequate monitoring shall be implemented to ensure that. Another way of solving this is to enable the TSOs to reject balancing or redispatching bids which deviate significantly from the spot price in a given hour[22].

It may also be argued that it is not the market structure which is limiting competition, but rather the physical constraints of the network, actually limiting the transfer of power. Artificially overcoming network constraints by merging the same bidding area nodes with limited transport capacity may result in artificially low prices in day-ahead, while generators with market power will just exercise their power in the redispatching / countertrade and / or the balancing market, possibly affecting even more seriously the end consumers. It should be stressed that, when reducing the size of the zones, the apparent increase of market share of a given producer in this zone, that may result in an increase of market power, is largely compensated by the increase or the development of competition linked to a better appraisal of true network capabilities and a more efficient allocation of transmission capacity linked to better locational information of bids/offers[23].

Market zones should be designed according to the real topology of the network and, in this way, the exercise of market power, which may be unavoidable in certain nodes/zones, will be more transparently identified.

In this context it should be noted that knowing the available transfer capacity between zones, and whether an interconnection may be congested or not before bidding, enables an actor to abuse a dominant position because he can speculate in high prices within an area or in the chance of receiving high remuneration in redispatching. On the other hand, if the available information to the market was focussed on e.g. the availability of critical branches (maintenance, outages, etc.) such as in e.g. the flow-based method, the possibility for abusing dominant position would be reduced.

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[22] According to Norwegian legislation, if it is apparent that price setting in the balancing market is inefficient from a socio-economic point of view, the TSO may reject bids and introduce the spot price for remuneration of the submitted balancing bids (§ 11 Forskrift om systemansvar). This paragraph mimics a market with perfect competition where bids are based on marginal cost.

[23] Financially binding bids/offers linked to a smaller zone are better than guesses of possible market outcomes made by TSOs concerning GSK (Generation Shift Key).

Liquidity

Very often, a reduction in the size of the zone is interpreted as a reduction in the liquidity of the day-ahead market.

This is, however, too simplistic a view, as the important parameter here is the overall liquidity of all zones covering a given territory: with the obligation to trade day-ahead between zones through implicit auctions, the volume (liquidity) of cross-zonal trade will benefit from "internal" trade that should otherwise not have been offered to the market coupling/splitting.

Overview of Relevant Legal Requirements

Annex I to EU Regulation 714/2009, Article 1.7 states that:

> *"When defining appropriate network areas in and between which congestion management is to apply, TSOs shall be guided by the principles of cost-effectiveness and minimisation of negative impacts on the internal market in electricity."*

Further, Article 1.8 states that:

> *"When balancing the network inside the control area through operational measures in the network and through re-dispatching, the TSO shall take into account the effect of those measures on neighbouring control areas."*

These legal provisions indicate how congestion management within one zone has an impact on flow and possibilities for congestion management in neighbouring zones.

The guiding principles shall be efficiency and that congestion is handled where it occurs. Moving congestion to the border shall be only the last resort (if at all) after other measures have been tried.

Today, congestion is in many cases routinely moved to the control area borders. It should be noted that in the case of Svenska kraftnät, the Commission has made the assessment that current practices are not acceptable. Therefore, Sweden will be divided into four bidding areas in 2011.

In the following, the different policy options for the definition and implementation of zones for CACM are described and assessed.

4.4.2.2 What are the policy options? What is their impact?

2.A. <u>No action on definition of zones for CACM (*Option 0*).</u>

Recalling the problem identification in Chapter 2 and the definition of general and specific objectives in Chapter 3, it follows that without further development of the definition of zones, the objectives of the future CACM will not be reached.

Moreover, a consideration of the three key criteria according to which the policy options need to be assessed yields also that the *Option 0* is not an acceptable one: neither the effectiveness (achieving the objectives set), nor the benefits (for the market participants, TSOs, customers and society as a whole), nor a consistency in terms of the trade-off between economic, social and environmental domain can be achieved by retaining the status-quo of the definition of zones as it is today.

It follows that *Option 0* is not the right policy option and that no action at EU level will lead to a deteriorated situation in terms of the definition of zones in the future. *Option 0* is therefore not considered appropriate for the definition of zones for CACM.

2.B. Zone = Country

2.B.1 Description of the Policy Option

Zones could be defined along national borders so that one country equals one zone. De facto, the implementation of the internal market in Europe has led to a zonal approach, with a mix of areas of different sizes corresponding usually to the political boundaries.

In the case where network topology and/or zones are defined along national borders, the borders may not correspond to network topology and/or structural constraints in the network, and thus the zonal division may not reflect the network in an efficient manner. This implies that the zones presumably encompass several structural congestion, which then has to be handled within a zone through redispatching or by moving the congestion to the border.

2.B.2 Real Life Example of the Policy Option

In most of continental Europe today, national (control area) borders define zones. This means that all producers and consumers within each country are faced with the same wholesale reference price.

2.B.3 Assessment of the Policy Option

When zones are defined along national borders, one zone will most likely contain several network constraints that give rise to structural congestion. This means that there will be inefficiencies, since the TSO will typically have higher costs of maintaining security of supply by redispatching, or the TSO will move internal congestion to the border. Also, the uncertainty associated with predicting flows in a large area with several internal constraints may lead the TSO to be more conservative in its estimation of available capacity on interconnectors, so that the network is not fully utilised.

National borders may in some cases coincide with a structural congestion as the physical cross-border capacity between countries is limited. Thus, national borders may be part of the borders for zones, but they should not be the leading principle for zone delimitation. Structural constraints and network topology are more relevant.

The current ATC capacity calculation methods used in continental Europe imply a risk of discrimination since they give an implicit priority to internal (national/intra-zonal) transactions on cross-border exchanges. This problem is exacerbated if small and large zones are mixed.

At the allocation stage, the presence of large zones prevents an efficient assessment of the impact of a given power exchange on the transmission network[24].

Finally, it should also be noted that this option is the easiest one to implement as it corresponds to the de facto current situation in most countries.

As a conclusion, this policy option is clearly feasible, but there is a risk that the capabilities of the network are not fully used and that the method may bring some discrimination between internal (national/intra-zonal) and cross-border transactions and therefore should be kept if it is demonstrated that the management of congestion inside the country is guided by the principles of cost-effectiveness and the minimisation of negative impacts on the internal European market in electricity.

2.C. Zone = Defined by Network Topology

2.C.1 Description of the Policy Option

Zones could be defined according to network topology. One alternative belonging to this policy option is to divide zones along structural congestion that is of a certain volume and duration. But structural congestion may be difficult to define. Another alternative is to define this delimitation according to critical infrastructure (as in flow-based approaches) by grouping nodes with similar influence on these critical network elements, as described in Power Transmission Distribution Factors (PTDF). The main criteria for assessing the delimitation of zone is the overall welfare gain of the new delimitation.

Congestion may occur inside a country or across borders. Therefore, this policy option implies that one country could be divided into several zones and may also mean that one zone may include parts of more than one country.

Factors that are relevant for congestion are the location of load, generation and network topology. New investments in generation units and new transmission lines make the determination zone delimitation a challenge. Since the definition of zones is related to the network structure, the implication is also that zones may need to be adapted when large structural changes occur.

[24] The use of assumptions on “Generation Shift Key” (GSK) in order to better estimate the participation of a given generation unit to a given power shift is currently being examined in the CWE region. GSKs normally describe the contribution of a power plant to a given power transfer. These assumptions on GSK constitute a new example of the circular problem encountered in capacity calculation. The presence of block bids in the planned CWE market coupling, aiming at facilitating the incorporation of starting constraints of generation units, exacerbates this difficulty and may jeopardise the chance of making relevant assumptions on GSKs.

2.C.2 Real Life Example of the Policy Option

The Nordic market, consisting of four countries, is currently divided into eight zones. Sweden and Finland each constitute one zone, whereas Norway and Denmark each are divided into four and two zones respectively. These zones are to a large extent defined by structural congestion in the network; however, the delimitations of the zones do, to some extent, follow national borders.

Sweden will be divided into four zones by 1 November 2011[25]. In its press release of 14 April 2010 regarding the future division of Sweden into four zones, the European Competition Commissioner Joaquín Alumnia said: "I welcome the commitments offered by Svenska Kraftnät which show the importance of integrating Europe's energy markets in order to improve security of supply to the benefit of European consumers. This case also shows the need for all operators of electricity grids to take a European perspective that goes beyond purely national boundaries when trying to address network congestion problems."

Italy is another example of internal zones. The Italian day-ahead market is based on six bidding zones, but whereas in the Nordic market, the number of bidding zones equal the number of (potential) price zones, in Italy there are different zonal prices on the supply side, with a uniform price (weighted average of the zonal prices) on the demand side.

2.C.3 Cost-benefits analysis

The analysis in this section is based on a study of the Nordic market [4], which shows that welfare gains can be achieved by improved coordination of the system operation function and allowing for a zonal definition that better reflects actual congestion.

The study shows that the choice of the zone definitions has a significant impact on congestion costs, and thus on the social surplus. For instance, choosing zones according to the limits of the system operators gives 38 % higher generation costs compared to optimal dispatch, whereas a zone delimitation which follows the physical modalities of the network only gives 5 % higher costs than the optimal dispatch. The study suggests that a zonal definition built on the physical modalities of the network, regardless of TSO or country borders, yields significantly higher social surplus (generation costs are reduced by a third) compared to a zonal definition based on control areas.

[25] Svenska Kraftnät has adopted a formal decision to subdivide the Swedish electricity market into four bidding areas from 1 November 2011. The decision is fully in line with the commitments offered to the European Commission, which were approved be the Commission 14 April 2010. The subdivision will follow the four internal cuts where transmission capacity is limited under certain conditions. Under the commitments, Svenska Kraftnät will no longer limit trading, instead allowing electricity flows to adjust to transmission capacity through market prices.

1000 NOK	Unconstrained dispatch[26] (UD)	Optimal dispatch (OD)	Zone = TSO /country	Zone = network modalities
Social surplus	64 275	64 113	64 051	64 105
% difference in reduced welfare compared to OD			- 38 %	- 5 %

Table 1 Social surplus with different zonal definitions

A zonal division, based on the physical modalities in the network with regards to location and capacity of supply and demand allows for more "direct" congestion management as opposed to more "indirect" methods such as countertrade and limiting congestion at the border to deal with internal congestion.

Dealing directly with internal transmission constraints through well defined zones may lead to larger price differences, but the need for special regulation through countertrading (redispatching) and incentives to move congestion to the border would be greatly reduced.

Furthermore, benefits in terms of more correct price signals to generators and consumers would be achieved. This is important both for short and long-term planning of production and consumption.

The study [4] concludes that there is potential for significant savings, and thus welfare gains, by harmonisation and better coordination of congestion management methods. In order to specify this more exactly, a more detailed grid model should be analysed, and more work should be put into developing realistic input data.

2.C.4 Assessment of the Policy Option

To the extent that zones are defined by network topology and/or structural congestion, this model yields a more efficient market and some of the benefits associated with nodal pricing in terms of a better utilisation of network and generation resources can be reaped.

However, one particular feature seems to be very important: when designing a regulatory framework for international electricity markets: the more the market design replicates the physical characteristics (congested lines) of the electricity transmission network, the more efficient, non-discriminatory and reliable the system is. For this reason, market arrangements based on zones which are formally delimitated and neglect internal congestion are not only discriminatory, charging their congestion costs at their borders, but also create significant problems at the moment of integrating with other markets. Additional provisions trying to counterbalance the negative distributional effects of an improper market mechanism

[26] Unconstrained dispatch is a theoretical optimum, it does not take account of capacity limitations.

may only provide a palliative treatment without guaranteeing long-lasting market equilibrium.

The definition of price zones inside a country is a complex issue that may take many years, as it may affect the pricing of electricity (but practical solutions exist for that). It also may affect the sharing of congestion revenues between countries/zones (in 2008, 1.7 B€ were collected on all European borders). This issue was not addressed during the PCG's work and may significantly delay the implementation of market coupling across Europe if fair agreements cannot be found. Therefore, the proposed policy should also deliver a coherent solution to this issue. The question of the allocation of these congestion rents, after deduction of the costs required to ensure the firmness of capacity back to network users and in particular to holders of long-term rights should be examined.

A better definition of zone boundaries should ensure lower redispatching costs. A reduction of the size of the zones may also facilitate the determination of base cases and lead to a reduction of the "pre-congested cases" (see section on capacity calculation).

Finally, it is important to closely examine the interaction of zone delimitation in the day-ahead and intraday time frame with balancing requirements.

2.D. Zone Definition within the Nodal Pricing Method

2.D.1 Description of the Policy Option

As already mentioned in section 4.4.1.2 1F, nodal pricing means that each transmission node corresponds to one zone, and that market participants submit their bids at the node where their generation or consumption is located. The locational tags on bids are important for the TSO in terms of knowing load and generation patterns, and on the other hand the locational differences give important price signals to market actors. It can be said of nodal pricing that system security and market mechanisms are combined in an optimal way.

This model stands apart from the other models (with flow-based capacity calculation presenting a step in the same direction) because price and flow are fully determined simultaneously within the same algorithm, based on bids in each node of the network.

Nodal pricing is normally combined with different levels of aggregation of nodes in order to provide more liquid hubs.

2.D.2 Real Life Example of the Policy Option

Nodal pricing is well known from literature, and is often referred to as an optimal model for electricity markets. Some electricity markets in North America (e.g. PJM) have implemented nodal pricing, likewise in New Zealand.

The current experience with nodal pricing is also that it is combined with uniform pricing to (a large part) of the retail market.

2.D.3 Cost Benefits Analysis

The evaluation of the costs and benefits linked to the implementation of a nodal approach presented below is based on a study made by Erin T. Mansur and Matthew W. White on “Market Organization and Efficiency in Electricity Markets”, June 30, 2009 [5]. This study compares the performance of the two most important market designs currently existing in the US, i.e. a decentralised market organisation where bilateral trading practices prevail and a centrally organised market like the one applied by PJM Interconnection.

Organised markets are considered more efficient than decentralised ones, but they are costly to design and to implement. It seems logical to raise the question of whether organised markets are worth their implementation costs.

The study involves a detailed comparison of the changes in markets efficiency for a large region of the Midwest in the US that results from the switch in October 2004 from a bilateral market to an auction-based market in one day resulting from the expansion of PJM to that area.

This study shows that the main benefits to be credited to the implementation of the organised market are an increased convergence of day-ahead prices (the price spread is reduced by 2 to 3 $ per MWh) and a dramatic development of the volume of electricity exchanged between the two regions (around 2000 – 2600 MW on average).

Gains from trade are estimated at 150 M$ a year in the case of bilateral trade, and to 313 M$ in the case of organised markets. The difference, which is 163 M$ a year, has to be compared with a total implementation cost of 40 M$. Therefore, the paper naturally concludes that the benefits resulting from a shift towards organised markets by far exceed implementation costs.

2.D.4 Assessment of the Policy Option

A nodal pricing system entails the use, at the allocation stage, of a more detailed model of the network than the other two policy options explained in relation to the definition of zones, whereas load and prices are calculated simultaneously. This shows a good compliance with the key three criteria for evaluation of policy options (effectiveness, efficiency and consistency).

The result is a higher utilisation of the network and optimal use of generation resources. Nodal pricing will reflect geographic differences in costs and willingness to pay for generators and consumers respectively, and these price signals are important both for short term generation patterns and long-term investment planning in the market.

At the same time, nodal pricing implies a radical change in current market design and the benefits of this implementation have to be further assessed in relation with expected benefits.

Also, the implications of nodal pricing in terms of multiple prices within one country, if not tackled properly, may be difficult to achieve politically.

Finally, possible consequences of the implementation of a Nodal Approach in the definition of zones, such as the impact on price volatility and the compatibility with generation parks with low flexibility (nuclear, coal, etc.) have to be carefully assessed.

4.4.2.3 Conclusions and Preferred Policy Options for the Definition of Zones

Zones should be defined according to network topology, i.e. physical constraints and location of supply and demand centres should be considered when zones are defined. The zonal division should ideally be robust enough to cope with changing load patterns due to seasonal variations as well as e.g. the expected increase in wind generation.

Currently in Europe many countries constitute one zone even though there may be internal congestion within those countries. In order to maintain one zone, TSOs have to handle this internal congestion with redispatch or by limiting cross-border capacity as a last resort.

With zones corresponding to network topology, benefits may be expected through a decrease in the need for redispatching, cross-border capacity limitation and moving congestion to the border. This will also benefit the market by delivering clear price signals of scarcity and oversupply and for production and investment planning, i.e. signals for both short and long-term planning.

In cases where it can be shown that there is no significant internal congestion within a country, one country may constitute one zone. However, the impact on other control areas/zones must be proven to be minimal.

Transparency on internal congestion shall be required, and reasons for reducing cross-border capacity must be transparently communicated.

The TSOs shall on a regular (continuous) basis submit the comparative analysis data on the redispatch costs and the market power / structure shall be evaluated by the NRAs.

The NRAs shall then assess whether the single price areas per country can be maintained (key criteria for that are the welfare gains and optimisation), or a split into more than one price area within a country is needed; in case of a split into more price areas, this shall be done along the real, physical bottlenecks in the network.

4.4.3 Objective #2: To Achieve Reliable Prices and Liquidity in the Day-Ahead Capacity Allocation

4.4.3.1 What is the issue?

The day-ahead market occupies a central position in the power trading timeline and, despite experienced, and a forthcoming increase in intermittent generation, its price remains the most widely used reference for both physical- and financial-based electricity markets.

The organisation of the day-ahead market and especially the corresponding congestion management methods should support an efficient dispatch of the generation units and an efficient use of the transmission network.

Pricing should usually reflect the variable costs of marginal generation plants. Prices established in the day-ahead markets serve as a reference for long-term products, such as futures and forwards.

Day-ahead markets are usually organised in hourly and standardised block products.

This time frame, corresponding to an anticipation of real time by 12 to 36 hours, is especially convenient for TSOs to perform the necessary system security assessments (including the evaluation of the needs for generation reserve capacity) and for market players with thermal units.

The functioning of the day-ahead cross-border market is strongly related to the way transmission capacity is calculated and to the definition of bidding zones, as explained above for the policy options in support of achieving Objectives 1-1 and 1-2.

Article 2.1 of Annex 1 (Congestion Management Guidelines) to Regulation (EC) 714/2009, indicates that:

> "*capacity shall be allocated only by means of explicit (capacity) or implicit (capacity and energy) auctions*", whereas "*both methods may coexist on the same interconnection*".

Article 2.8 of the above Annex acknowledges that:

> "*where forward financial electricity markets are well developed and have shown their efficiency, all interconnection capacity may be allocated through implicit auctioning*".

The target model (Annex 4) elaborated for the day-ahead CACM is a ***single price coupling implicit auction***, using a single algorithm for establishing prices and volumes across zones.

The following are the key requirements to achieve that:

- Harmonised gate closure times;

- Full exchange of all bids among involved Power Exchanges (in case more than one PX is servicing the area); and

- Compatible bids and products.

The description of the day-ahead Target Model indicates also a number of open issues which are mainly related to governance questions (decision-making, sequence of deployment path, etc.). It is considered important to address all these open issues accordingly in the future CACM framework and in the envisaged governance guideline.

4.4.3.2 What are the policy options? What is their impact?

3.A. <u>No action on the day-ahead market (*Option 0*).</u>

The significance of day-ahead capacity allocation for the physical and financial electricity markets has been clearly explained before. A plethora of different approaches exist in the EU for day-ahead CACM today, including: coordinated explicit auctions, implicit auctions with market splitting (which are equivalent to the Target Model with single price), implicit auctions with market coupling and volume coupling, etc.

Without a common EU-wide initiative on day-ahead capacity allocation, the EU-wide and even inter-regional convergence towards the defined Target Model for the day-ahead market will only be achieved after many years, if at all.

Moreover, because of the dependency between the forward market and the liquidity and reliability of prices in the day-ahead market, the adequate development of the forward market would also be postponed by the delays in day-ahead capacity allocation convergence and integration.

It follows that, by no action on the day-ahead market and capacity allocation, neither of the three key objectives for the evaluation of policy options is satisfied: effectiveness (no effectiveness due to hampering achievement of a common, EU-wide day-ahead capacity allocation platform), efficiency (no market efficiency and improved welfare and trading opportunities without a common day-ahead capacity allocation platform throughout the EU), consistency (due to a delayed common day-ahead capacity allocation platform in the EU, social and market benefits are not achieved and the "zero" initiative is not consistent with the defined objectives and goals of the CACM).

Recalling the problem identification in Chapter 2 and the definition of general and specific objectives in Chapter 3, it follows therefore, that without further development of the day-ahead capacity allocation and market integration, the objectives of the future CACM will not be reached.

Option 0 is therefore not the right policy option and no action at the EU level will lead to a deteriorated situation in terms of day-ahead capacity allocation in the future.

Option 0 is therefore not considered appropriate for the day-ahead capacity allocation within the CACM.

3.B. Explicit Auctions

3.B.1 Description of the Policy Option

The explicit auction mechanism allocates the available transmission capacity to the market participants bidding the highest prices for the capacity between price zones. Explicit auctions can be performed bilaterally or in a more coordinated manner for a certain geographic area (e.g. via regional auction offices).

In principle, day-ahead explicit auctions do not necessarily require coordination or even the existence of organised spot markets, and are easy to implement: transmission capacity is granted to the highest bidders, i.e. to the operators attaching a higher value to it. More specifically, in an explicit auction, the auction manager gathers the bids for each hour of transmission capacity availability: first, it assigns the capacity required to the bid with the highest price, and then descends until the available transfer capacity for the hour (or block of hours) is completely assigned. The price of the capacity is usually set as the price offered by the last accepted bid. From the bidders' standpoint, explicit auctions require a good level of internal coordination between their operations on electricity and transmission capacity.

3.B.2 Real Life Examples of the Policy Option

Since the legal framework does allow for explicit auctions and their implementation is relatively simple, this was and still is the allocation method used at most of the European continental borders (e.g. Northern borders of Italy, France-Spain, France-England, CEE Region) for day-ahead capacity allocations.

3.B.3 Assessment of the Policy Option

In explicit auctions, capacity is traded separately from energy. The time gap elapsed between the matching of capacity bids and offers and the nomination procedure may result in a sub-optimal allocation due to transactions potentially performed in a non-economical direction. Indeed, due to the separation of energy and transmission capacity into two products, it cannot be excluded that transactions are done in an inefficient direction, i.e. from the high to the low price area.

Explicit day-ahead auctions are not considered to be a sustainable solution, but are simple with regard to feasibility, and may be considered to be a transitional solution to be developed further towards an increased level of coordination.

3.C. Implicit Auctions – Volume Coupling

3.C.1 Description of the Policy Option

Implicit auctions refer to the fact that transmission capacity is cleared together with energy prices. Implicit auctions and the clearing made by PXs can normally be interpreted as the result of a welfare maximisation process based on available bids/offers (Consumer and Producer Surplus Maximisation – CPSM – problem).

Volume coupling has been designed to create a possibility to couple markets where the preconditions for price coupling do not yet exist. Volume coupling proceeds to a selection of bids and offers based on the maximisation of welfare corresponding to available bids and offers. Price dependent flows between zones are calculated, and given back as input to the coupled PXs for their price setting process.

Volume coupling requires less calculation and harmonisation of data than price coupling. The level of tightness in volume coupling can vary from so-called loose volume coupling in one end, to tight volume coupling on the other. The efficiency of tight volume coupling may be very close to price coupling.

3.C.1 Real Life Examples of the Policy Option

As explained in the Annex 6.1, in the real world example of the implicit auction with volume coupling, volume coupling does not calculate prices and may require less harmonisation of data than price coupling,.

3.C.2 Assessment of the Policy Option

Volume coupling does not calculate prices for coupled areas. The lack of harmonisation between the different rules applied for price setting by the involved PXs may lead to a lack of coherence in the separately calculated prices. The efficiency of volume coupling depends on the degree of coordination/harmonisation reached among involved Power Exchanges: if all order books are exchanged ("tight volume coupling"), social welfare gains may be comparable to a situation with price coupling, although price discrepancies may remain and interconnections may still be sub optimally used; in the case where all order books are not shared ("loose volume coupling"), efficiency may be as low as in day-ahead explicit auctions.

This is explained in detail in Table 3 of [6]. This policy option could therefore be considered as a transitional solution to be developed further towards an increased level of coordination, such as price coupling.

However, great vigilance must be exercised when volume coupling and price coupling overlap. The risk that different coupling schemes introduce sub-optimal results must be carefully taken into account.

When evaluating this policy option in terms of the defined main and additional criteria, it follows that it satisfies, in principle, the three main criteria (effectiveness, efficiency and consistency), but it does not meet the additional criteria, most notably those of competition and transparency.

This policy option is therefore only considered appropriate as a temporary approach, but not as a sustainable, long-term solution.

3.D. Implicit Auctions – Price Coupling, ATC Based

3.D.1 Description of the Policy Option

In a price coupling mechanism, a single, centralised clearing algorithm is used for the determination of volumes and prices in all coupled/ split zones. If there is not enough capacity between the zones, calculated prices differ and the price difference is equal to the price of congestion. In other words, the price for transmission capacity corresponds to the difference of the marginal cost (including opportunity costs) of electricity at the different locations (zones) as reflected in the participant's bid.

The day-ahead cross-border transmission capacity is used to integrate the spot markets in the different bidding areas in order to maximise the overall social welfare in both (or more) markets. The capacity is in fact awarded to the most efficient bids for selling electricity in the surplus areas thus minimising the purchasing costs in the deficit areas. In implicit auctions, the transmission capacity between bidding areas is made available to the spot price mechanism in addition to bid/offers per area, thus the resulting prices per area reflect both the cost of energy in each internal bidding area and the cost of congestion.

This policy option is mainly used in combination with "traditional" ATC capacity calculation. The application of a Flow-based method for the single matching algorithm is described in Annex 6.2.

3.D.2 Real Life Examples of the Policy Option

Price coupling is performed in the TLC (Trilateral Coupling between France, Belgium and The Netherlands), in the Nordic area (by the Power Exchange Nord Pool), in MIBEL (by the Power Exchange OMEL in Portugal and Spain) and in Italy, as described in the Annex 6.2.

3.D.3 Cost Benefit Analysis

The cost benefit analysis of the implicit auction with price coupling has been conducted by the CWE Market Coupling Project, indicating clearly a positive outcome in favour of a price coupling implicit auction[27].

3.D.4 Assessment of the Policy Option

The implementation of price coupling is crucial to finding market clearing prices at the scale of the whole market and if one wants to avoid creating inadequate incentives, which are volume transactions that are not supported by prices.

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[27] See the Implementation Study made by the CWE Market Coupling project available at:
http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/Central-West/Final%20docs/Implementation_Study.pdf

From the policy options outlined for day-ahead markets, price coupling has clear advantages in terms of efficiency. All bidding information is used in a single coordinated price formation (optimisation) at the same point in time. This results, per definition, in an optimal outcome (given the limitations imposed by an imperfect modelisation of the network). Volume coupling and explicit auctions are less efficient.

Some products allow market players to impose additional conditions on their offers. The most common examples are block bids, which require that an offer be accepted for a consecutive series of hourly slots. Block bids are usually presented on the supply side by generators relying on thermal or nuclear thermal power plants, requiring steady output flows in order to minimise their operating costs: the block bid, if accepted, allows the generator to take into account ramp-up costs and to maximise its revenues. On the other side, a block bid on the demand side allows consumers to secure the power necessary for a given process, constituting a sort of hedging contract against unexpected hikes in prices.

Drawbacks linked to this policy option are linked to the issue of capacity calculation and zones delimitation mentioned before, which may render the implementation of this policy option especially difficult.

Implicit auctioning suggests that further considerations are needed regarding the roles and responsibilities of TSOs and Power Exchanges in coordinated matching.

3.E. Implicit Auctions – Price Coupling, Flow-based

3.E.1 Description of the Policy Option

Like implicit auctions and the clearing made by PXs, a FB allocation can normally be interpreted as the result of a Consumer and Producer Surplus Maximisation (CPSM problem.

Within an electric power system, maximisation is subject to restrictions given by the network. Physical laws imply that a meshed network is a single system where actions at some locations have an impact throughout the rest of the network. These impacts can be described by sensitivity coefficients (the Power Transmission Distribution Factors (or PTDF)). These coefficients describe the impact of a given electricity exchange/transaction on network elements.

Compared to “ATC” based implicit auctions, a Flow-based allocation process takes into account, at the allocation stage, these mutual impacts through the use of PTDF factors in order to better assess system security. Each zone or country is no longer seen as a copper plate and (internal) network constraints may be taken into account.

No ex-ante available transmission capacity is published by the TSOs for market players (even if Available Maximum Flows (AMF) on critical branches may be published).

The complexity of the algorithm necessary to perform price coupling is mainly linked to the presence of block orders which introduce a degree of inflexibility. If the amount of block bids is too important, there is a risk that it is not possible to find a (zonal) market clearing price (that satisfies producers and consumers). This problem is rooted in the presence of generator constraints and has nothing to do with the use of transmission constraints (ATC), a flow-based model or even nodal. If nothing can be done on the number or proportion of flexible generators in a given system, enlarging the number of flexible generators participating in the energy market facilitates the finding of a market clearing price, as well as a reduction of the size of the zones.

In flow-based allocation, a more detailed underlying grid model could allow a higher utilisation of the network. The treatment of the additional constraints linked to a more detailed representation of the network has only a limited impact on the complexity of the algorithm compared to the problems raised by the block orders.

3.E.2 Real Life Examples of the Policy Option

At present, there are no real life examples of the flow-based single price implicit auction (market coupling).

Nevertheless, in the CWE region for example, the MOU signed in 2007 between Member States, regulators, TSOs, PXs and representatives of producers foresees the implementation of a flow-based market coupling.

Moreover, in the CEE region, where the focus has been put on the flow-based capacity calculation (mainly because until just recently, there was no reliable and liquid pricing in all of the countries in the CEE region), it is envisaged that explicit auctions shall be replaced by implicit ones with price coupling as soon as possible after the introduction of the flow-based calculation.

3.E.3 Assessment of the Policy Option

A Flow-based allocation is expected to have advantages to efficiently use network capabilities and at the same time to ensure network security. This option may prevent arbitrary reservation of transmission capacity for security reasons.

The physical flows observed in a specific network element (a power line) correspond to the superposition of the physical flows generated by all exchanges (transactions) taken individually. This rule is also called the superposition principle.

This law of physics has a fundamental consequence concerning the design of efficient electricity markets. A buyer and seller’s maximum gains from trade depend on production decisions of other players elsewhere in the network. But others’ production is private information, and is not observable by all parties it affects.

Achieving efficient trade in electricity corresponds to a complementary goods problem: complementary character arises when two production facilities are separated by a congested portion of the delivery network. In such circumstances, additional trade does not necessarily exacerbate network congestion.

This makes it desirable to pair transactions that alleviate congestion with transactions that otherwise would create it: these trades are called complementary trades. In a meshed network, the search for complementary trades requires the simultaneous knowledge of the characteristics of the network (topology through PTDF), and of the valuation and production quantity at every node in the network.

The main difficulty is constituted by the fact that a single bilateral trade may not be feasible, but multiple bilateral trades may be simultaneously feasible. A centralised organisation of the electricity market (single price coupling), simultaneously gathering information on the location (zones), the volume and the value of the trades helps to achieve an efficient allocation of transmission capacity. This is why price coupling, using flow-based allocation is more efficient and why a bilateral trade model of electricity on a network is less efficient.

This allocation method is also market-based, in the sense that market players decide how to use the available transmission capacity. This is especially important in meshed areas for the sharing of the available transmission capacity of (critical) network elements on different borders with large mutual influence.

However, the implementation of Flow-based Method implies additional complexity and an up-front cost of changing the system, whereas bilateral coordinated ATC requires less up-front work as it is mostly implemented already. This is why e.g. in the CWE region, the first step towards this method will be relying on the ATC capacity calculation.

Finally, as for other implicit allocation methods, the feasibility of this policy option is linked to an appropriate delimitation of zones, as explained before.

4.4.3.3 Conclusions and Preferred Policy Options for the Day-Ahead Capacity Allocation

The preferred option for day-ahead capacity allocation is the implicit auction performed by a single (centralised) price coupling.

From the market participants' point of view, the market may still consist of several Power Exchanges so that the actors would submit their bids to the PX where they are located. The centralised price coupling mechanism shall have a monopoly on capacity between PX areas. There will be cases where one PX sets the price for several zones, i.e. market splitting (such as the Nordic market and MIBEL for Spain and Portugal).

To the degree that zonal divisions are successfully based on network topology, price signals in the day-ahead market will give information about scarcity and oversupply, and thus deliver robust reference prices for other time frames. For market actors this means, in particular, crucial information for investment planning as well as short term generation optimisation.

4.4.4 Objective #3: To Achieve Efficient Forward Market

4.4.4.1 What is the issue?

There is a need for cross-border risk hedging mechanisms in order to have an internal and seamless European energy market across all timeframes. One key role of the forward market is to provide market participants with the ability to manage risk associated with cross-border trading. It is useful to distinguish between Transmission Rights (either PTR or FTR) based on the underlying cross-border capacity and thus allocated by TSOs, and Financial Derivatives, such as Contracts for Differences which are not linked to the physical capacity and which thus can be issued and allocated by third parties, e.g. financial market places.

Importance of Long-term (LT) rights

The general identified objective of long-term transmission rights, be it physical or financial, is to provide to market players long-term hedging solutions against congestion costs in day-ahead markets. Long-term transmission rights should facilitate cross-border (zone) trading, competition and provide efficient and reliable long-term price signals.

Issues related to LT rights

The main issues to be discussed in relation to long-term rights concern firmness and secondary markets either via Power Exchanges or OTC (Over-The-Counter).

Firmness mechanisms are currently based on the market price differential or reimbursement (usually with an additional compensation) of the initial price for the capacity. Firmness is considered important for the establishment and functioning of forward markets. Hedging the risk of short-term price volatility can only succeed if the financial value associated with the capacity remains and is not affected by possible events after allocation, e.g. curtailments. The calculation of the risk premium conducted by potential buyers depends on the robustness of the right in question. Without firm capacity, the value of the transmission right will decrease due to the risk premium.

A harmonised approach to firmness is linked to a harmonised definition of force majeure. The definition of force majeure decides on (when) the TSOs' obligation to bear the risk and to pay compensation to the capacity owner.

Firmness of capacity is not free, and asking TSOs to improve firmness might encourage them to minimise long-term capacity.

In the presence of financially firm long-term transmission products, secondary markets will become more attractive. The establishment of a liquid secondary market is of vital interest to market participants as it provides the capacity owner with an additional option of making unneeded capacity available for the market by receiving a fair price and an additional way for market participants to acquire the needed transmission capacity. TSOs may be responsible for establishing and managing organised secondary markets.

The relevant legal requirements for the forward markets are described in Annex 7 and the related Target Model for the EU CACM, encompassing also the forward market and related capacity allocation, in Annex 4.

4.4.4.2 What are the policy options? What is their impact?

4.A. No action at the EU level (*Option 0*);

At present, there is no common or at least coherent / compatibly approach for the long-term electricity market or for a "real" forward market throughout the EU. Whereas some regional coordinated approaches exist – most notably the common forward market in the Nordic area – they are limited to a region and do not provide for EU-wide liquidity and / or efficiency of the Internal Electricity Market.

While the physical (day-ahead and intraday) market is essential for the liquidity and effectiveness of any forward market, finding a common and coherent approach for organising it is equally important if the IEM objectives are to be met.

Therefore, *Option 0*, in the sense of no EU-wide initiative towards common principles for the forward market is both technically and economically insufficient and not in line with the existing (and new 3rd Package) provisions.

Option 0 is therefore rejected as inadequate for achieving the objectives.

4.B. Physical Transmission Rights with UIOSI Mechanism

4.B.1 Description of the Policy Option

The TSOs auction Physical Transmission Rights (PTRs). These rights provide the right but not the obligation (in case of options) to transport a certain volume of electricity in a certain period of time between two price zones.

With a UIOSI mechanism, the owner of PTR may either use the capacity for physical transmission or has the right to receive the congestion price (positive value only). In the first case, the owner of the capacity nominates the capacity (in total or at least partly) until the corresponding gate closure time. In the latter case, the capacity not nominated will be transferred automatically back to the TSO in order to be allocated in the day-ahead time frame. In the case of implicit auctions, the owner of a PTR with UIOSI may receive the day-ahead market price differential, if positive.

This mechanism provides a hedge against potential congestion costs.

The UIOSI mechanism could theoretically imply that the owner actively returns unused capacity back to the TSO in order to provide it for the implicit allocation procedure. In this document, however, it is understood that UIOSI entails an automatic resale of capacity not nominated.

Very often, the volume of PTR is determined on the basis of worst case scenarios ensuring that the offered right is “sufficiently” firm. Volume of long-term rights are also linked to preventive redispatching/countertrade[28].

4.B.2 Assessment of the Policy Option

Implementing PTRs with UIOSI mechanism transfers the efficiency issue to the day-ahead mechanism given that the capacity is transferred automatically or deliberately to the day-ahead allocation procedure. So, the risk of nominations against market price differential will be reduced even if it is still an issue but the unused capacity is not lost since it is allocated through the day-ahead mechanism.

Traders may decide not to use the PTR for physical transmission purposes but to receive the market price differential, but this depends in practice on the actually implemented provisions for firmness and compensation in case of curtailment or other reasons.

The risk of nomination against the actual price differential may thus be diminished as nomination is only an option for the capacity owner. It can always choose not to nominate but to use the financial hedging function of the UIOSI mechanism instead.

Even though UIOSI may be linked to explicit auctions as well, the best results as regards efficiency of capacity allocation will be generated with day-ahead implicit auctions.

Operating PTR-based long-term capacity markets, especially without the UIOSI mechanism, may lead to less capacity volume in the day-ahead market. Long-term transmission capacity that has to be nominated and that is thus managed by the implicit allocation mechanism in day-ahead may have an impact on the volume available for the day-ahead market as it reduces the amount of capacity to be offered in that time frame.

PTRs with UIOSI is a physical capacity product and is therefore closely linked to the market design most broadly implemented throughout electricity markets in the European Union today.

The establishment of this product might therefore be less complicated for most of the Member States than the introduction of a new product, even though it does not deliver the highest optimum and welfare.

[28] http://www.entsoe.eu/fileadmin/user_upload/_library/publications/etso/Congestion_Management/2-ETSO-An_evaluation_of_preventive_countertrade_final.pdf

4.C. Financial Transmission Rights

4.C.1 Description of the Policy Option

Financial Transmission Rights are transmission rights issued by the TSO as a hedge against congestion costs between zones/countries. With an FTR, the owner does not get the right to physically transport electricity. FTRs entail the right to receive a financial compensation equal to the congestion rent i.e. the price differential between price zones.

FTRs may be designed either as options or as obligations. In this paper, option is understood as the right to receive the positive market price differential. There is no additional obligation on the owner's side. In contrast, FTRs designed as obligations do provide the same right but entail also the obligation for the owner to pay the respective market price differential if it is negative, i.e. if the price differential is in the opposite direction.

With FTRs, the whole physical transmission capacity may be given to the day-ahead implicit auction. FTR implies suppression of long-term nominations. More specifically, the TSO receives the initial price paid from the beneficiaries for FTRs issued (by auctions). Afterwards, the capacity is transferred to the day-ahead market where the TSO gets the corresponding congestion rents (the market price differential in the day-ahead market). This amount will be passed to the owner of the FTR.

In order to ensure equivalent revenue for FTRs issued and due to the fact that the congestion rent received by the TSO (based on the implicit auction outcome) is the limiting factor, the amount of FTRs issued and physical capacity available have to correlate. In the case of obligations, flow-based method may be used for the allocation (auctioning) of FTRs as it may take advantages over the netting of commercial exchanges. In this case, it can be shown that the volume of issued FTR has to be simultaneously feasible in order to be neutral for the TSO (see previous paragraph)[29].

4.C.2 Assessment of the Policy Option

As all available capacity from FTRs may be rendered to the day-ahead auction procedure automatically, the risk of nomination contrary to market price development disappears. Thus, the FTR environment may provide for a more efficient allocation that ameliorates the present situation significantly at many borders, which is achieved in a similar way through the cross-border financial markets.

[29] ETSO paper, section 2.2.5
http://www.entsoe.eu/fileadmin/user_upload/_library/publications/etso/Congestion_Management/Short%20ETSO%20Risk%20hedging%20in%20CM_final%20PUBLIC.pdf

In addition, it is ensured that all physical capacity is available to the day-ahead market as a whole without reduction due to nominations before that point in time as with PTRs with UIOSI.

As financial products are new to most of the energy markets in the European Union it is still not fully clear whether FTRs are linked to financial or legal side effects that have not been identified and assessed yet.

In addition, the question may arise whether FTRs are to be regarded as financial instruments or as physical transmission products entitling a financial compensation based on price differentials on day-ahead physical markets. In the first case, one might come to the conclusion that FTRs are not within the scope of energy regulation. The need to ensure efficient oversight over these products remains. These vital questions have to be answered before implementation of FTRs.

It should be noted that FTRs require as a prerequisite the implementation of implicit auctions and thus power exchanges.

4.D. Hybrid Option

4.D.1 Description of the Policy Option

Between having only FTRs or only PTRs with UIOSI there is a wider range of combinations of both instruments. These may differ with regards to the respective percentage of FTR and PTR with UIOSI.

4.D.2 Assessment of the Policy Option

Operating both systems synchronously would require two separate trading platforms as there two different products would exist – one for FTRs and one for PTRs (with UIOSI). Due to the different allocation systems for these products, the trade would be segmented which consequently triggers less liquidity in both segments while increasing operational costs and thus fees.

This policy option is therefore not considered further, even though it might be compliant (at least “formally”) with most of the criteria defined before for the policy assessment.

4.4.4.3 Conclusions and Preferred Policy Options for the Forward Market and Allocation

There are two basic options to enable risk hedging for cross-border trading, FTR, PTR and, in the case where there are liquid and well developed financial markets, a third option through financial instruments such as Contracts for Differences.

As the original capacity owner and beneficiary as regards congestion rents, long-term capacity products shall be provided by TSOs to market participants. Due to the same economic outcome, PTR combined with a UIOSI mechanism shall be implemented in the short term starting with a regional implementation approach, whereas introduction of FTRs shall be prepared for the medium term.

At the same time, the possibility to implement FTRs immediately between some regions/countries/zones might be given, provided that the necessary coordination with (existing) PTR with UIOSI mechanism between other regions/countries/zones is ensured in order not to hinder progress in the market integration process.

PTRs with UIOSI and then FTRs (later on) shall equal the total volume of physical transmission capacity as the linkage between quantities of financial hedging products and physical capacity ensures TSOs' ability to pay redispatching and countertrading costs as well as congestion prices without additional financial risk.

A market in financial derivatives organised by third parties can offer cross-border hedging possibilities for market participants. CfD (Contract for Differences) is an example of such a product.

Within regions where forward financial markets are well developed and have shown their efficiency, the introduction of PTRs and FTRs shall not be necessary. Financial derivatives not linked to transmission capacity can be considered as an adequate alternative, and be introduced or continued to be used. This is also clearly stated in Regulation (EC) 714/2009.

4.4.5 Objective #4: To Design Efficient Intraday Market Capacity Allocation

This CACM objective addresses the design and implementation of an efficient intraday cross-border market, in support of better trading opportunities, reduced balancing needs and effective integration of massive variable generation (wind). The time frame considered as intraday is any time after the day-ahead stage and before Gate Closure Time (GCT[30]).

4.4.5.1 What is the issue?

The key feature of the intraday market is to provide market participants with an efficient way to balance their positions before real-time and trade energy as close to real time as possible. Intraday trade is particularly important in order to take into account variable generation, e.g. wind.

European national and cross-border markets for intraday trading are generally less well developed than equivalent forward or day-ahead markets. However, intraday markets are important as they provide market participants with a wider range of options to balance their position in response to unanticipated changes in production and consumption.

[30] Gate Closure Time refers to the final moment in which market players are able to trade electricity or inform the balancing responsible party of their position before real time delivery, without it affecting their balancing position.

Functioning intraday markets should reduce overall system costs and provide more efficient flows. Intraday markets should also enable TSOs to manage (new) congestion (by redispatching – where applicable and possible) and allow the start of new generation units for security reasons.

The anticipated increase in renewable generation is a key driver of the need for an efficient intraday market solution. Renewable generation can be difficult to forecast on a day-ahead basis and becomes more predictable closer to real time.

As a consequence, intraday markets are likely to see an increase in activity as market participants may trade out imbalances as close to real time as possible.

Co-existence of different mechanisms

Under some existing market designs, it is possible for several mechanisms for intraday trade and capacity allocation to co-exist. This includes different procedures to allocate capacity and tools for TSOs to manage congestion on the network (redispatching) and market participants to adjust generation and demand. The general issue is the degree to which intraday mechanisms should be harmonised to achieve efficient trade and to integrate intraday markets.

The existence of several intraday mechanisms results in segmentation of intraday markets and may increase the market power of some players[31]. A lack of coordinated operation and the interaction of different pricing rules may result in inefficient or unanticipated outcomes.

It is also important that any proposal for intraday markets is compatible with day-ahead and balancing mechanisms (see below). In particular, marginal pricing rules are common for these times frames.

Capacity reservation

Another issue related to intraday is the need to support this trading activity by ensuring availability of sufficient capacity in the intraday time frame. It should be noted that any capacity reserved for intraday (and balancing time frames) will have the effect of reducing the capacity available in day-ahead and that this impact will scatter through the interconnected system.

For this reason, and for efficiency, as a general rule, no capacity reservations should be made for intraday. The same rule should in principle be applied to cross-border balancing: intraday capacity should not be decreased by reserving capacity for this purpose. Nevertheless, in cases where socio-economic welfare gain and benefits can be proven, capacity reservation for intraday trade could be introduced and used, under the condition that it is continuously monitored and evaluated by the responsible regulatory authorities.

[31] For example, there is a risk that the combination of redispatching/countertrade rules with the intraday mechanism may result in some generators being paid for corrective actions that do not correspond to a change in the generation level.

Balancing

Although balancing is outside the scope of this IIA, the interaction between intraday and balancing time frames needs to be addressed to ensure the policy options proposed for the intraday time frame can facilitate a better functioning of balancing markets.

Balancing starts after the gate closure of intraday market. Therefore, all cross-border activities at this level should be managed by TSOs. In order to maximise market integration at this time frame, any cross-border trade should be based on a common merit order between TSOs. For the same reasons, no reserve price should be applied.

A clear driver for intraday trade in the current framework is the obligation for market parties to be balanced in real time in their balancing zone and the associated pricing of imbalances. There is a risk that actions decided on the basis of this rule may create or exacerbate congestion that will have to be managed by TSOs by redispatching/countertrade. With current balancing arrangements, there is a lack of proper incentives for market participants to align their individual behaviour (profit maximisation) with overall welfare. This non-coordination of intraday objectives with redispatching/countertrade may result in a less efficient functioning of the market.

Redispatching

In the absence of new events in the intraday (and balancing) time frames, trade accepted in day-ahead (implicit auctions) is firm, and no redispatching/ countertrade actions (except those linked to structural redispatching: see above) should be necessary. No additional costs are required for the delivery of electricity in real time.

In normal circumstances, many events occurring in intraday may necessitate redispatching actions to ensure the (financial) firmness of trade concluded in day-ahead. Intraday congestion may occur as market players may not follow their schedules announced in day-ahead and on the basis of which security assessments were performed. The question of how to charge these redispatching / countertrade actions on market players who are responsible for it should then be examined. It must be emphasised, however, that this question can be addressed from another side by relying on balancing pricing, and this shall be elaborated in detail when developing the IIA and FG on Electricity Balancing Markets Integration.

Congestion pricing

Congestion pricing is a key issue in congestion management, especially for the intraday (and balancing) time frames.

In the day-ahead market and capacity allocation, the principle of coarse (function of the delimitation of the zone) congestion pricing through implicit allocation of transmission capacity between zones is more or less accepted. The price of transmission capacity corresponds to the difference of the marginal cost (including opportunity costs) of electricity at the different locations (zones) as reflected in the participant's bid. This principle means that market players who want to consume at a given location (zone) have to pay the marginal price for producing electricity in that zone, and that generators are rewarded by the same marginal clearing price for producing electricity in the zone.

In the intraday market, such a principle does not exist and TSOs give the possibility to market players to adapt their schedules close to real time and to trade in order to be balanced. This organisation may ignore the costs (externalities) resulting from a change of schedule on other market players, through redispatching costs for the management of congestion or through the obligation for some TSOs to reserve transmission capacity margin in order to secure unexpected loop flows.

Gate closure time and harmonisation

The different gate closure times which currently exist in Europe could impact on the development of an integrated cross-border intraday market and potentially act as a barrier to trade. In evaluating the options for the intraday time frame, it is important, but not a prerequisite, to consider harmonised gate closures and to weigh the GCT close to real time vs. operational security. The advantages of shortening gate closure time, closer to real time, should carefully be examined. In particular, the option of the activation of tertiary reserves by the use of the intraday mechanism in a more competitive environment should be studied, without forgetting however that while intraday market possibilities are related to the portfolios, the balancing / reserve markets are different in this point.

Legal framework

The existing CM guidelines state that the design of cross-border intraday markets shall give efficient economic signals, promote competition and be suitable for Community wide application. Intraday congestion management shall be established in a coordinated way no later than 1 January 2008, shall be market-based and allocated only by means of explicit or implicit auctions. For intraday trade, continuous trading may be used.

The CM guidelines also state that establishing reserve prices shall not be allowed.

With a view to promoting fair and efficient competition and cross-border trade, coordination between the TSOs within a region shall include capacity calculation, the use of a common transmission model and an allocation mechanism dealing efficiently with interdependent physical loop-flows.

4.4.5.2 What are the policy options? What is their impact?

4.A. <u>No action at the EU level</u> (*Option 0*);

The significance of the intraday market is growing with the growing portion of variable generation in European control areas. An efficient and well harmonised (throughout the EU) intraday market would not only allow to cope with the volatility in market operation close to real-time, but would also help reduce balancing and regulating of power reserves, reducing thus also the costs. Finally, harmonised and well coordinated (throughout all EU control areas) intraday markets, functioning together with the integrated balancing markets, will eventually also contribute to maintaining operational security.

Therefore, no action towards harmonised and coherent approach to the intraday market in the EU is an inappropriate way from the technical, economical and also legal perspective (bearing in mind the existing and future provisions for the IEM).

Option 0 is hence rejected and not considered further.

4.B. Explicit Continuous Trade

4.B.1 Description of the Policy Option

In explicit continuous allocation, the available transmission capacity is allocated to the participants by the TSO on a first come first served basis. Given the lack of a price mechanism, capacity is often made available to participants for free. The transmission capacity is allocated to the market separately and independently from the trading of energy. Market participants purchase energy OTC or on power exchanges and nominate their flows against their capacity holdings. Sometimes, allocated capacity is combined with an obligation to use the requested capacity.

Examples of this allocation method can be observed on Germany - France and on Germany - Netherlands interconnections.

4.B.2 Assessment of the Policy Option

This allocation mechanism is easy to implement and provides flexibility for market players. Nonetheless, it is the least likely to result in efficient flows. This is because market participants face the risks and complexity associated with coordinating their capacity and energy positions. In addition, explicit first come first served allocation is not market-based and does not necessarily result in capacity being allocated to those who value it most and in welfare maximisation.

For these reasons, this option will not be further assessed as a preferred policy option for the EU-wide, coordinated intraday market.

4.C. Explicit Auctions

4.C.1 Description of the Policy Option

In explicit auctions, transmission capacity is auctioned to the market separately and independently from the trading of energy. Market participants bid for the capacity from the TSO and then purchase energy on power exchanges or OTC and nominate their flows.

The capacity bids of network users determine the value of capacity in each intraday auction. Where there is no congestion, explicit auctions should result in capacity being allocated for free. Where congestion exists, the price of capacity will be determined by market participants' willingness to pay, reflecting arbitrage opportunities and market participants' balancing requirements.

Explicit auctions take place at specific time periods throughout the day to allocate any available, unused or netted capacity.

This allocation method is currently used on the England - France interconnection[32] and France - Spain interconnection.

4.C.2 Assessment of the Policy Option

This allocation mechanism is market-based and not discriminatory as capacity is allocated to market participants with the highest willingness to pay[33]. If the intraday auction price is robust[34] it will facilitate meaningful arbitrage with longer term capacity products and provide a good indication of network congestion closer to real time.

This in turn should result in economically efficient flows being scheduled across interconnections, hence welfare maximisation. Nonetheless, the fact that market participants are required to coordinate their energy and capacity positions, and the risks associated with this, may reduce intraday liquidity and result in flows in an uneconomic direction. This is because market participants have incomplete information on regional generation and demand and have to coordinate actions across the relevant capacity and energy markets. Market participants may also face a higher risk of imbalance costs if domestic market arrangements are not sufficiently harmonised. For these reasons, in practice, and given a rather low liquidity of intraday markets currently, this mechanism may not be very efficient.

Furthermore, auctions have to be very frequent to provide market players with the flexibility they need in this particular time frame.

On the other hand, as the existence of power exchanges is not a precondition for explicit auctions they may represent a suitable interim mechanism in some regions, where networks are not heavily meshed and borders are independent.

4.D. Implicit Auctions

4.D.1 Description of the Policy Option

Intraday implicit auctions operate in the same way as day-ahead implicit auctions described within the Objective #2 considerations. The TSOs determine the available capacity, which is notified to market participants. They post energy bids and offers on power exchanges, which are combined for different markets or price areas and

[32] There are two intraday explicit auctions that take place at 17:00 (CET) on D-1 and 08:20 (CET) on D. Capacity that has not yet been sold in long-term or day-ahead auctions and any released via UIOLI or netting is offered in the intraday auctions. The auction is a market clearing price auction.

[33] Market participants that identify the largest arbitrage opportunity or face the biggest balancing risk.

[34] If the interconnected markets are competitive and market participants have sufficient information regarding arbitrage opportunities and balancing risks.

matched until either prices converge or the available interconnector capacity is fully utilised.

Current designs have recourse to a series of intraday auctions of products for the remaining part of the day, e.g. between Spain and Portugal.

4.D.2 Assessment of the Policy Option

Implicit auctions are a market-based mechanism which tend to result in more efficient use of interconnector capacity than explicit auctions. This is because all information related to generation and demand is used to schedule transactions between market areas. As market participants are not required to coordinate their energy and capacity positions and are not exposed to imbalance risk, implicit auctions may facilitate and optimise cross-border trading compared to explicit auction.

Related to this, implicit auctions also provide a greater possibility for trading activity to be coordinated across a meshed network, through a flow-based implementation, taking into account congestion externalities caused by loop flows. This should also facilitate a more efficient use of the existing transmission infrastructure, particularly in highly meshed networks.

As implicit auctions provide an intraday reference price for each market area they may also promote more efficient generation dispatch and locational investment decisions than other mechanisms. Furthermore, depending on the delimitation of prices zones, implicit auctions may be able to provide an efficient congestion pricing. However, the validity of these price signals, whether market prices or congestion pricing, has to be carefully checked if the liquidity of the market is not sufficient.

Using the same clearing principle as the day-ahead market (marginal pricing; pay as cleared), this method may avoid gaming and inefficient (from a social welfare point of view) arbitrages between the day-ahead and the intraday time frames.

At the same time, the welfare maximisation algorithm provides a way to put all bid/offers on the same level playing field, to promote competition and avoid discrimination between hourly and block orders (which are important for the starting of generation units in intraday) products.

However, as implicit auctions take place at specific times (gates) they may not be sufficiently flexible to allow for fast intraday adjustments. Market participants would have to wait for each auction to adjust their intraday positions. In order for implicit auctions to provide a sufficient level of flexibility, it would be necessary to introduce at least hourly auctions.

All in all, implicit auctions in intraday are an efficient and acceptable solution provided hourly gates are in place and market conditions (such as liquidity) are met to give efficient and reliable price references (and thus flows). In such a case, the necessary coordination with neighbouring regions should be ensured. Nevertheless, they may be costly to implement, while they do not offer the technical features really needed by market participants, e.g. flexibility or trading possibility as close to real time as possible.

4.E. Implicit Continuous Allocation (Trade)

4.E.1 Description of the Policy Option

Implicit continuous allocation means that market participants are able to match visible (dependent on the transmission capacity) bids and offers on a single regional or European trading platform, on a first come first served basis.

In a continuous trading system, capacity is allocated as the needs of market participants appear. This implies that no congestion occurs until the last trade possible, if any. Consequently, such a mechanism does not require nor provide for any congestion pricing, especially as TSOs are not allowed to set a reserve price. As a result, intraday capacity is allocated for free.

The available capacity is updated following each successful bid and offer. This may result in the fact that some offers/bids may become invisible from a given location as a consequence of an agreed trade. This mechanism may also allow the trade of block order products linking several hours. To enable a fully implicit allocation of capacity, cross-border OTC trades should no longer be possible as such. Block bids and later special products (with start-up costs for instance) may replace the need for OTC, but further investigation is required here.

This form of allocation is currently used on Elbas, the cross-border intraday market in the Nordic Region. This platform allows the trade of block orders products linking several hours.

Implicit continuous trading has obtained a wide consensus and it is the general target model for intraday in the conclusions of the Project Coordination Group, as explained in Annex 4.

4.E.2 Assessment of the Policy Option

Implicit continuous allocation allows market participants to trade energy through a single platform for all participating market areas on an almost instantaneous basis. This provides market participants with access to a large pool of liquidity to adjust their positions in response to an unanticipated event. As market participants are not required to coordinate their energy and capacity positions and are not exposed to imbalance risk, implicit allocation should encourage cross-border trading and liquidity.

Generally, implicit continuous allocation requires a lower degree of harmonisation and coordination than implicit auctions which means that they are simpler to implement.

Current implementation of this continuous model allows the use of block orders together with hourly products. Since block orders span over several hours, their visibility cannot be coordinated with the visibility of the other hourly products. (It is worth recalling that in continuous implicit mechanism, the visibility of bids/offers from a given market place reflects the limitations existing on cross-border/zonal transmission capacity. A block order may be “in the money” and therefore should be visible at a given hour and “out of the money” and therefore not visible the following hour.) There is a lack of competition between the two types of products and a risk of discrimination in favour or at the expense of these blocks orders. The visibility of block orders, reflecting cross-border capacity limitation, should be carefully examined as it may result in a shift of liquidity from the day-ahead towards the intraday time frame.

However, the model allows the matching of block orders with hourly orders.

Implicit continuous trading is a market-based mechanism, used in other markets as well, since cross-border capacity is allocated to the most efficient trades at a given time, with the exception of block orders. This mechanism may be compatible with a flow-based allocation of capacity.

Nevertheless, as trades are accepted on a first come first served basis and deals are also continuously updated, implicit continuous allocation may not always result in the most efficient flows being scheduled, and may not be as efficient in terms of social welfare maximisation as implicit auctions. This is especially true for trade based on sequential bilateral arrangements on an electrical network with important externalities caused by loop flows [5].

Furthermore, *a priori*, continuous trade does not allow for congestion pricing, which may be necessary when significant additional capacity becomes available. Nonetheless, mechanisms to price congestion may be designed in case significant additional capacity becomes available in an already congested direction. This has to be further studied.

Continuous trading has another important consequence concerning the bidding behaviour of market players. With a clearing mechanism and a marginal pricing rule (like in day-ahead), market players are incentivised to bid at (or just above) their marginal costs, in order to maximise their chance for being in the merit order, and still receiving the marginal (highest accepted) price for their energy. In continuous trading (most likely with a pay as bid mechanism), market players might be incentivised to bid at their guess of the market needs, and not according to their actual costs and to arbitrage between the different time frames.

Trading and optimising in a continuous environment may require a team of dedicated specialists continuously following the market. As a consequence, it might be more complicated than posting bids (for remaining generation capacity) for the beginning of intraday time frame on the basis of the results of the day-ahead market, and thus favour big market players.

As a conclusion, for all the above mentioned reasons, implicit continuous allocation may be less efficient from a theoretical point of view than implicit auctions, but may cope better with the needs of the intraday market (flexibility or trading possibility as close to real time as possible), and be less costly and easier to implement. Finally, this mechanism has received a strong and wide support from market players and has been verified in practical use.

4.4.5.3 Conclusions and Preferred Policy Options for the Intraday Market

The intraday market shall enable actors to close their positions before the operational hour. Functioning intraday markets should reduce overall system costs by contributing to more efficient flows. The intraday market may also enable TSOs to manage new congestion by redispatching and allow the start of new generation units for security reasons. The expected increase in wind generation may make intraday more important as prognostication in day-ahead becomes more uncertain. Thus, in addition to allocating cross-border capacity in an efficient way, the intraday market shall provide flexibility to market players, be practical and easy-to-use and allow them to balance their positions as close to real time, providing it does not hamper TSOs to ensure network security. In this respect, there is a need to study further how balancing markets (in particular slow tertiary, manually activated, reserves) may interact with the intraday market.

There are several options for organising intraday trade. In this IIA, explicit continuous, explicit auctions, implicit auctions and implicit continuous trading have been assessed.

The overview of the assessment of the various options shows that implicit methods meet most of the criteria applied for the policy options assessment and are superior to explicit allocation methods.

This evaluation delivers two preferred policy options: implicit auctions and continuous implicit trading.

The debate on the preferred option for the intraday markets concentrates on those policy options that offer simplicity of use and are more flexible and faster to implement (continuous allocation methods) against the options that lead to a better welfare maximisation (implicit auctions).

Explicit mechanisms should only be envisaged as a very short-term solution.

Implicit auctions are the most efficient way to allocate cross-border capacity. But to meet practical needs of market players in intraday, auctions will have to be frequent.

Implicit auctions remain an option though, having in mind that price references, congestion pricing and capacity allocation may only be really relevant if the market is sufficiently mature and liquid.

On the other hand, recognising the lack of speed of implicit auctions, implicit continuous trading appears to be a good solution in the absence of significant amount of additional transmission capacity.

To tackle some of these flaws, additional features can be implemented, including for example:

- Automating matching could act as an implicit auction when opening the intraday market or when reassessing available capacity.

  In such cases, it will ensure that capacity is allocated to the one who is willing to pay the most, allow for a flow-based allocation and might even provide congestion pricing if required.

  This should be further elaborated in the future by ENTSO-E and PXs.

- Market players' behaviour should be monitored, as is currently done today, but having in mind the possible undesirable incentives market players may have to arbitrage (against welfare) and game between the different time frames.

To maximise trade possibilities and gains, implicit continuous trading should be enabled throughout the whole of Europe.

Locally or regionally, other mechanisms – e.g. implicit auctions – could be implemented, if deemed appropriate, provided they are compatible with the European system.

Such hybrid solutions should be introduced after careful analysis, in order to avoid any adverse effects on the EU-wide approach for the intraday trade.

4.5 Preferred Policy Options for the CACM - Summary

Capacity Allocation and Congestion Management issues are universally appealing, affect all kinds of stakeholders and the multiple relationships between them. Therefore, the policy options chosen should be flexible and expressed as a combination of complementary alternatives, among which the most suitable one may be selected depending on the topic and parties it deals with.

In this regard, the Objectives identified in Chapter 3 have been matched above with the possible policy options to achieve them and the impacts of these policy options evaluated in terms of effectiveness, efficiency and consistency.

The preferred overall policy option for the future CACM regime in the EU is therefore expressed in the following terms:

1) In order to achieve <u>Objective #1-1: To ensure optimal use of transmission network capacity in a coordinated way – Capacity Calculation</u>, the two main policy options shall be implemented for short term capacity calculation:

   Flow-Based Method for capacity calculation makes use of locational information in the grid model, and thus allows for a more optimal calculation of load flow and thus utilisation of the network. This method is therefore considered to be the best one for capacity calculation in cases where transmission networks are meshed and interdependencies between the interconnections are high (e.g. ENTSO-E Continental Europe, most notably the regions CWE and CEE).

   ATC is considered a feasible method for less meshed networks, such as the Nordic power system or possibly the cases of interconnections between the large peninsulas or islands in Europe. However, this method must be applied with due caution as it is essential to ensure that capacity constraints within one control area are managed in order to minimise any adverse impacts on neighbouring control areas (countries).

In both cases, long-term calculation methodologies shall be fully compatible with the short term capacity calculation, take into account the actual impact of commercial transactions on the physical grid situation and the fact that basic input data only has limited reliability because of changing market situations.

2) For Objective #1-2: To ensure optimal use of transmission network capacity in a coordinated way – Definition of Zones for CACM the applicable policy options are:

   In cases where it can be shown that there is no significant internal congestion within a country, ***one country may constitute one zone***. However, the impact on neighbouring countries must be proven to be minimal.

   Transparency on internal congestion shall be required, and reasons for reducing cross-border capacity must be transparently communicated. The TSOs shall on a regular (continuous) basis submit the comparative analysis data on the redispatch costs and the market power / structure shall be evaluated by the NRAs.

   The NRAs shall then assess whether the single price areas per country can be maintained (key criteria for that are the welfare gain and optimisation), or a split into more than one price area within a country is needed; in case of a split into more price areas, this shall be done along the real, physical bottlenecks in the network.

3) In line with the Objective #2: To Achieve Reliable Prices and Liquidity in the Day-Ahead Electricity Market, the policy options are defined:

   The preferred option for the day-ahead capacity allocation is the ***implicit auction performed by a single (centralised) price coupling***.

   In cases ***where there is no power exchange, explicit auctions may be used*** as long as no sufficiently liquid and reliable price signal is available.

4) For the Objective #3: To Achieve Efficient Forward Electricity Market, the preferred policy options include:

   The options for enabling risk hedging for cross-border trading are ***Financial Transmission Rights***, ***Physical Transmission Rights with UIOSI*** and, in the case where there liquid and well developed financial markets exists, ***financial instruments such as Contracts for Differences***.

   FTRs should be considered for introduction on interconnections between regions with well developed financial markets and other regions with less developed financial markets.

   An introduction of FTRs on interconnectors within such a region may only be done if efficiency gains can be documented.

5) Within the Objective #4: To Design Efficient Intraday Market, the policy options are defined:

   Implicit auctions and ***continuous implicit trading***.

   Explicit auctions should only be envisaged as a very ***short-term solution***.

Within this scope and contents, the FG for CACM shall be developed, to be followed by the respective detailed network codes.

Moving to jurisdiction attribution, system operators should be entitled to impose the fulfillment of, and monitor the compliance with, the defined CACM requirements. Their authority in this field should be ensured in the same terms across all of the EU territory, as a steady, homogeneous reference.

Further, mandatory enforcement is suggested in order to ensure compliance with the framework guidelines and network codes, since the experiences with a voluntary approach suggest that it will not deliver results, at least not in a reasonable time frame.

Whereas the preferred policy option(s) described above will require extensive adaptations of the existing framework in some cases, the level of such adaptations must be carefully governed by the overarching goal to address only cross-border relevant CACM issues. On the other, given the nature of capacity allocation and congestion management and its impact on cross-border trade, is it anticipated that most of the CACM is indeed relevant for cross-border trade.

Furthermore, the main objective of the framework guidelines is to highlight which emerging questions/problems with regard to CACM issues should be solved, leaving the approaches on how to solve them to the related network code(s).

Nevertheless, the framework guideline should be detailed enough to cover all necessary issues on own merits, but leaving space for detailed and customised arrangements where applicable to be defined in the network code(s).

Here, a clear role for the European Commission is to enforce common codes, standards and procedures. The subject of this initial impact assessment and the Framework Guidelines for Capacity Allocation and Congestion Management is therefore an essential contribution towards that direction.

ANNEX 1 - Glossary and Abbreviations

Term	Definition
ACER	Agency for Cooperation of Energy Regulators
AMF	Available Maximum Flows
ATC	Available Transfer Capacity, defined by the ETSO method
CM	Congestion Management
Common Grid Model, CGM	Set of data describing the transmission network, connected generators and demand allowing load flows calculations shared between TSOs. This data should be updated and refreshed in accordance with the concerned time-horizon.
Countertrade	Generally regarded as a subset of redispatch and normally considered as a preventive measure; nevertheless, curative countertrade is in principle possible too.
CPSM	Consumer and Producer Surplus Maximisation (problem)
Curative methods	Employed to resolve unexpected congestion after gate closure, during the day of operation.
DA	Day-ahead
DACF	Day-ahead congestion forecast
ENTSO-E	European Network of Transmission System Operators – Electricity
FB	Flow-based
FTR	Financial Transmission Rights are products whose owner does not get the right to physically transport electricity but obtains the right to receive the congestion rent, i.e. the price differential between adjacent price zones. In the context of this Impact Assessment, FTRs are assumed to be issued by TSOs, as congestion rent owners.
FG	Framework Guidelines
GSK	Generation Shift Keys
IEM	Internal Electricity Market
LT	Long-term (capacity rights)
NTC	Net Transfer Capacity, defined by the ETSO method
OPF	Optimum Power Flows
OTC	Over-The-Counter trading is to buy and sell products such as commodities or derivatives directly between two parties, as opposed to exchange trading, which occurs via facilities constructed for that purpose (exchanges).
PCG	Project Coordination Group
PTDF	Power Transfer Distribution Factors (matrix used in the flow-based capacity calculation to indicate the dependencies between the nodal injections and flows in the branches)
PTR	Physical Transmission Rights are products whose owner becomes entitled to use interconnection capacity for actual electricity transfers between two price zones. In the context of this Impact Assessment, FTRs are assumed to be issued by TSOs, as congestion rent owners
Preventive CACM methods	Employed in the operational planning phase, before gate closure. In a system with market-based CACM and no preventive countertrade, the marginal equilibrium price in each area reflects the costs of providing electricity in that area. If preventive countertrade is used to guarantee or increase the firm transmission capacity, congestion costs may be blurred and the true marginal equilibrium price not revealed.
Redispatch	A general term covering every method with the objective of changing generation or load

Term	Definition
	schedules, often perceived as synonymous in its effect, to the countertrade
rTPA	regulated Third Party Access
TC	Transfer (or Transmission) Capacity
TRM	Transmission Reliability Margin
TTC	Total Transfer Capacity
UIOLI	(use-it-or-lose-it) Capacity linked to a physical transmission right characterised as such becomes lost without compensation if holder doesn't nominate product in due time (usually in day-ahead market) and freed for usage in subsequent stages. This mechanism is therefore linked to explicit, pure physical transmission rights
UIOSI	(use-it-or-sell-it) This mechanism characterises a physical capacity product that can be used either as physical transmission right or as the right to receive congestion rent obtained due to implicit allocation/auction mechanism. In the first case, the owner has to nominate the capacity in order to indicate the will to physically transport electricity. In the later case, the owner does not nominate; the physical transmission right transmutes automatically to the implicit allocation/auction where it is allocated. Congestion rent generated in this implicit allocation/auction is paid out to the owner. In the context of this Impact Assessment, UIOSI is used also in the sense of similar terms like "UIOGPFI (use-it-or-get-paid-for-it) or "automatic resale".

ANNEX 2 – Mandate for ERGEG to Develop FG for CACM

In a letter of 26 March 2010 to the ERGEG President from the Director of the Commission's DG Energy, the Commission invited the ERGEG to submit the FG for Capacity Allocation and Congestion Management:

"… In recognition of the importance of ensuring the effective application of the institutional framework established by the Third Package for the establishment for a European integrated energy market, there is general agreement among stakeholders that it is appropriate to begin work on the development of framework guidelines and the network codes as soon as possible.

In this context, ERGEG has declared its readiness to undertake the role envisaged for the new Agency for the Co-operation of Energy Regulators in anticipation of the application of the Third Package rules, in particular Agency Regulation (EC) 713/2009. Similarly ENTSO-E has indicated that it is ready to undertake the functions assigned to the ENTSO for Electricity to be formally established in accordance with Electricity Regulation 714/2009.

On this basis, we reached agreement at the last meeting of the Florence Forum to begin work on pilot framework guidelines and network codes on rules governing connection to the transmission system in electricity, on rules governing capacity allocation and congestion management and capacity calculation and rules governing security standards and system operation. This work will serve two functions: firstly, stakeholders will benefit from the experience of working with the new processes before their actual applicability, supporting the effective implementation of the third package when all the new bodies have been formally established, secondly this will enable substantial progress to be made in this important area, supporting the integration of renewable energy and helping achieve the policy aims set out in the Energy Policy for Europe and the Strategic Energy Review.

I therefore invite ERGEG to assume the role assigned to the Agency under Article 6 (2) of the Electricity Regulation and to submit within 6 months of receipt of this notification

- a Framework Guideline on Grid Connection Rules;

- a Framework Guideline on Capacity allocation and Congestion Management

"…In developing the Framework Guidelines, you should apply the procedures and obligations as defined in the Electricity Regulation and the Agency Regulation, in particular with regard to transparency and consultation obligations…"

ANNEX 3 - List of References

[1] "*Commission Impact Assessment Guidelines*", http://ec.europa.eu/governance/impact/commission_guidelines/commission_guidelines_en.htm

[2] "*Comparison between ATC based and flow-based allocation in the CEE region*", Consentec Study for the CEE TSOs comprising Verbund APG, CEPS, E.ON Netz, ELES, MAVIR, PSE-O, SEPS and VE-T, Final report, 14. October 2008, http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/Central-East/Final%20docs/TOP_3_Consentec_CEE-TSOs_FB-ATC-Comp_final_14-10-2008_Ad.pdf

[3] "Definitions of Transfer Capacities in Liberalised Electricity Markets", ETSO Final Report, April 2001, http://www.entsoe.eu/fileadmin/user_upload/_library/ntc/entsoe_transferCapacityDefinitions.pdf

[4] Bjoerndal, Mette, Joernsten, Kurt: "*Benefits from Coordinating Congestion Management – The Nordic Power Market*", Energy Policy, Vol 35, No. 3, pp. 1978-1992, March 2007

[5] Erin T. Mansur, Matthew W. White: "Market Organization and Efficiency in Electricity Markets", June 30, 2009, http://bpp.wharton.upenn.edu/mawhite/papers/MarketOrg.pdf

[6] "ETSO-EuroPEX Interim Report on Development and Implementation of a Coordinated Model for regional and Inter-Regional Congestion Management", http://www.entsoe.eu/fileadmin/user_upload/_library/publications/etso/Congestion_Management/Report.pdf

ANNEX 4 – EU PCG Target Model for CACM

According to the results of the work of the PCG (Project Coordination Group)[35], the CACM Target Model for capacity calculation will have to build on a common grid model with a clear emphasis on increased coordination and cooperation between TSOs, especially on system security issues. This shall be constituted either by a coordinated assessment of cross-border (cross-zonal) ATC approach or by a flow-based calculation.

Following steps of the capacity allocation process identified during PCG's work are the determination of cross-border capacity (step 2) and the allocation the transmission capabilities to market players. The application of a flow-based method does not necessitate step 2; network security constraints being explicitly taken into account at the allocation stage.

The link between the determination of transmission capacity (TC) and preventive redispatching / countertrade measures was identified during the work of the PCG on a Target Model. Likewise, the relationship between delimitation of zones and the need for redispatching was recognised, i.e. zones based on network topology imply a lesser need for redispatching. Nevertheless, the way to organise this redispatching, to ensure the availability of these resources and to charge the corresponding costs was not examined.

The Target Model for the forward market proposed by PCG examines both primary capacity markets and trading of capacity in secondary markets. As regards primary markets, the target model focused mainly on two options (FTR and PTR with UIOSI) and recognised a third option as an intermediate step, especially where sufficiently liquid financial markets exist. No recommendation has been made, however, on a final solution as both options were deemed to provide equally efficient hedging possibilities. On the intraday market, the Target Model has considered both implicit auctions and continuous trading, but also did not recommend a clear preference for one of them.

[35] Further details about the PCG's work is available here: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_WORKSHOP/Stakeholder%20Fora/Florence%20Fora/PCG

ANNEX 5 – Detailed Considerations and Examples for Coordinated Capacity Calculation

ANNEX 5.1 – Summary of Legal Provisions Relevant for Capacity Calculation

Article 15.2 of Regulation EC 714/2009 specifies that:

> *"The safety, operational and planning standards used by transmission system operators shall be made public. The information published shall 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 schemes shall be subject to the approval of the regulatory authorities".*

Article 16.3 of Regulation EC 714/2009 specifies that:

> *"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 1.7 of Annex 1 of the Regulation, which corresponds to the Congestion Management guidelines, indicates, concerning where capacity calculation should apply, that:

> *"When defining appropriate network areas in and between which congestion management is to apply, TSOs shall be guided by the principles of cost-effectiveness and minimisation of negative impacts on the internal market in electricity…"*

Finally, the proposed capacity calculation method should allow a market-based allocation of transmission capacity which is mentioned in Article 2.1 of Annex 1:

> *"Congestion-management methods shall be market-based in order to facilitate efficient cross-border trade…"*

and Article 2.7:

> *"…The highest value bids, whether implicit or explicit in a given time frame, shall be successful".*

Article 3.1 of Annex 1 also indicates that:

> *"Capacity allocation at an interconnection shall be coordinated and implemented using common allocation procedures by the TSOs involved. In cases where commercial exchanges between two countries (TSOs) are expected to affect physical flow conditions in any third-country (TSO) significantly, congestion-management methods shall be coordinated between all the TSOs so affected through a common congestion-management procedure..."*

Finally, Article 3.5 describes what coordination means:

> *"With a view to promoting fair and efficient competition and cross-border trade, coordination between TSOs within the regions set out in point 3.2 shall include all the steps from capacity calculation and optimisation of allocation to secure operation of the network, with clear*

assignments of responsibility. Such coordination shall include, in particular: the use of a common transmission model dealing efficiently with interdependent physical loop-flows and having regard to discrepancies between physical and commercial flows...”

ANNEX 5.2 – Capacity Calculation: ATC Method

Based on the ETSO definition published in 2001, the Total Transfer Capacity (TTC) is the maximum exchange programme between two areas, compatible with operational security standards applicable at each system if future network conditions, generation and load patterns were perfectly known in advance[36].

TTC is always related to a given power system scenario i.e. generation schedule, consumption pattern and available network that constitute the data allowing to build up a mathematical model of the power system (load-flow equations). The solution of this model (the result of the load flow calculation) is the so-called base case and is the starting point for the calculation of TTC.

TTC from area A to area B is computed by a stepwise increase of generation in area A and by a corresponding decrease of generation in area B. This process is carried out up to the point where security rules in either system A or B are breached. The maximum (commercial) exchange from A to B compatible with security rules (without taking into account uncertainties and inaccuracies: see below) corresponds to the TTC from A to B.

Transmission Reliability Margin (TRM) is taken into account in order to take uncertainties linked to the load-frequency regulation, emergency exchanges between TSOs to cope with unbalanced situations in real time and inaccuracies, e.g. in data collection and measurements.

The Net Transfer Capacity (NTC) is defined by: NTC=TTC-TRM, whereas for a given time frame, ATC is equal to the NTC less capacity already allocated at previous time frames.

This is the method most commonly applied throughout Europe, and it implies that TSOs estimate the capacity prior to knowing the actual flow (prior to actors’ submitting bids in day-ahead or to the PX).

This estimation prior to knowing the needed flows, entails that TSOs have an incentive to be conservative in their estimation because of the cost of redispatching and eventually possible operational security constraints. This is so because when setting capacity the TSOs need to forecast how the load and generation will be within their control area.

Forecasts are by their nature uncertain and TSOs need to put extra weight on possible outcomes that are critical to the security of the system.

[36] See http://www.entsoe.eu/fileadmin/user_upload/_library/ntc/entsoe_transferCapacityDefinitions.pdf

Therefore, the capacity delivered to the market will be lower than what would be the case if the actual load and generation patterns were known.

ANNEX 5.3 – Capacity Calculation: Coordinated ATC Method Example

In the Coordinated ATC Method, the base case definition and implementation is a key and decisive step for the success.

Suppose that the base case is constructed from a feasible common snapshot based on data observed for a day preceding the allocation as given by the Day-ahead Congestion Forecast (DACF) and that resulting flows are very close to the security limits of the system.

Then, suppose further that the cross-border exchanges that are removed from the common snapshot actually go in the opposite direction from the national exchanges on constrained network elements. In this case, an arbitrary separation of internal and cross-border exchanges may bring the operation point of the system outside the security domain. Electrical networks have indeed this property that some individual exchanges (trade) are not feasible but that all exchanges taken together are feasible due to Kirchhoff laws and due to a possible compensation on critical network elements linked to the spreading of electrical flows due to one exchange on the whole network.

TSOs' simulations in the CWE region covering the whole of 2007 have indicated[37] that, in 17% of the simulated cases, on the basis of automatic calculations (with no manual interventions), the network was already constrained in the base case, leaving no room for additional (cross-border) exchanges. The CWE TSOs also indicated that some manual verification may reduce this amount, but here again no automatic results would be possible.

This phenomenon has been called "pre-congested cases" and is linked to the existence of an artificial first step where some exchanges are de facto accepted and others have to undergo the allocation process.

[37] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/Central-West/Final%20docs/Implementation_Study.pdf, page 32

ANNEX 6 – Detailed Considerations and Examples for Day-Ahead Capacity Allocation

ANNEX 6.1 – Example of an Implicit Auction with Volume Coupling

An example of the implicit auction with volume coupling is the EMCC Market Coupling between the TPS interconnector (linking Germany to West Denmark) and the Kontek interconnector (linking Germany East Denmark), taking also into account in its calculation 4 other bidding areas: Estonia, Latvia import, Latvia export, and Russia import. In addition, the Baltic Cable (linking Sweden and Germany) joined the EMCC Market Coupling since 10 May 2010. After some problems occurring shortly after the go-live in 2008, the restart in autumn 2009 was done, and since then that it is considered to work properly. The ultimate target of EMCC is to grant capacity in order to allow the flow of electricity from low price areas to high price areas, bringing forward price convergence between contiguous areas.

However, EMCC does not allocate the total capacity of the two interconnectors, but only the so-called Market Coupling Capacity (MCC), leaving aside the capacity previously traded in explicit auctions.

The mechanism is the following: power exchanges (EPEX and Nord Pool) collect bids from market participants in their respective market areas, and transmit them anonymously to EMCC, which in turn calculates the optimal flow in the two interconnectors, in order to minimise the price differential between different market areas.

Once EMCC's capacity calculation algorithm is resolved, resulting capacity is sent to TSOs, and related price-independent bids are communicated to the power exchanges involved.

ANNEX 6.2 – Example of an Implicit Auction with Price Coupling

The Nordic power exchange Nord Pool Spot runs a day-ahead market[38] based on implicit auctions. The market is divided into zones[39] (elspot areas) within which producers and consumers submit bids. The price calculation takes into account the available capacity on interconnectors between zones, and in the case where there is congestion between zones this is relieved through market splitting. Nord Pool Spot also produces a system price which is the unconstrained equilibrium price which serves as a reference for the wholesale (OTC) and retail market as well as the forward markets / products.

In the case where there is internal congestion within zones, this is handled through countertrading by the TSOs during the operational hour.

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[38] Nord Pool Spot is a voluntary market; 25-30 % of total consumption in the Nordic area is traded bilaterally. In 2009, 72 % of the market was traded through Nord Pool Spot.

[39] As of June 2010, it was 10 zones; 5 in Norway, 2 in Denmark, one in Finland and Sweden respectively and finally EstLink constitutes one area.

In Italy, the Italian Power Exchange IPEX acts as the central market splitting auction house: it clears the national day-ahead market taking into account the price differentials between “zones”, i.e. areas which are characterised internally by the same electricity price, given that there are physical limits to transmission capacity to other, contiguous zones. IPEX then clears electricity bids matching them at to the so-called “Intake Points” and “Drawing Points”: for each zone, the equilibrium price is defined according to purchase offers and sale bids presented for the same zonal Intake and Drawing points. This constitutes an incentive towards building power plants in areas where demand is higher than electricity supply, ultimately contributing to distribute the generation park efficiently across the national territory.

ANNEX 6.3 – Cost-Benefit Analysis of the Implicit Auction with Price Coupling in the CWE Region

In 2008, the CWE Market Coupling Project assessed the economic benefits of the implementation of ATC-based and flow-based market coupling.

The implementation of a mechanism allocating cross-border capacity implicitly ensures that this capacity is always efficiently used, i.e. either the prices converge or cross-border capacity is fully used in the direction of the price differential. This optimised allocation generates a surplus for generators in the exporting zone, a surplus for the consumers in the importing zone and a well-calibrated congestion rent for the TSOs, while reducing arbitrage revenues to zero.

To investigate and quantify the results, the 2007 historical data were used, including order books and ATC values. For the flow-based part, flow-based parameters were reconstructed.

It should be kept in mind that this approach has some limits. For instance, bidding behaviours are supposed to be the same in the market coupling environment as in the isolated market environment. Likewise, it was assumed that market participants would not change their bidding strategies in a case of the flow-based calculation and allocation system. As a consequence, an overestimation of the benefits of market coupling is foreseeable.

Main conclusions of this exercise are:

- Compared to explicit auctions, an ATC market coupling with Germany increases total social welfare by 36.4 M€ for 318 days (around 41.8 M€ for the whole year, using linear extrapolation).
- Auction income increases by 21.6 M€ annually;
- Prices tend to converge more than under explicit auctions;
- The volatility decreases for all markets and, in particular, less extreme values are observed; and
- Market clearing volumes decrease slightly due to the absence of arbitrage volumes.

Comparing the ATC-based market coupling with the flow-based approach has resulted in the following outcome:

- Generates a total social welfare lower by 10.5 M€;
- Enables a similar price convergence;
- Tends to increase volatility in smaller hubs; and
- Produces more often prices out of the bounds defined by the isolated prices.

In particular, in the case of flow-based, the results above have to be considered with caution as the hypotheses behind the calculation influence the results, especially insofar as parameter definition criteria are likely to evolve and to be improved by the TSOs. Moreover, a more recent and detailed comparison [2] needs also to be taken into account, where the welfare gain and impact of the flow-based capacity calculation has been analysed in further detail.

The budget presented in the Addendum to the Implementation Study for the CWE region encapsulates costs of the design phase and of the implementation phase, including costs for the flow-based market coupling. The design phase cost is 7.5 M€. The implementation phase costs amount to 25.7 M€. Thus, the total project budget is around 33.2 M€.

For an initial investment of 33.2 M€, the project would generate around 41.8 M€ of additional social welfare compared to explicit auctions, based on real life data. Assuming 2007 is representative of the coming years and using an 8% actualisation rate, the project will generate more than 120 M€ of Net Present Value in 5 years.

Including additional operational costs (hypothesis: 2 M€ per year), the Net Added Value remains higher than 110 M€ in 5 years.

ANNEX 7 – Summary of Legal Requirements of Relevance for the Forward Market

The Congestion Management Guidelines stipulate (Article 2.5) that the access to medium and long-term allocations shall be firm transmission capacity rights which may be designed either as UIOLI or UIOSI. This Article refers implicitly to PTRs since FTRs are not subject to UIOLI or UIOSI (there is no nomination stage for FTRs).

In addition, Article 3.2 stipulates that:

> "*…a common coordinated congestion management method and procedure for the allocation of capacity to the market at least yearly, monthly and day-ahead shall be applied…*"

Finally, Article 2.8 stipulates that

> "*In regions where forward financial electricity markets are well developed and have shown their efficiency, all interconnection capacity may be allocated through implicit auctioning*".

The Guidelines do not specify explicitly whether long-term products are to be issued either as pure physical products or in the form of "financial" products and therefore leave the door open for financial transmission rights.