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Proposal of new variants for day ahead, intra-day and balancing markets/mechanisms in Europe

OPTIMATE project deliverable D23; D34; D35

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OPTIMATE

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PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the consortium (including the Commission Services)	
CO	Confidential , only for members of the consortium (including the Commission Services)	

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General purpose

The purpose of this document is to describe potential market design alternatives to be considered within the OPTIMATE meta model. The analysis focuses on Day-Ahead (DA), Intra-Day (ID) and balancing markets. Design options are described and their potential impact on massive intermittent RES-E market integration is assessed. This leads to an outlook on 'target market designs' which are to be modelled in OPTIMATE

This document includes the following contractual deliverables:

Deliverable number:	**D23**
Deliverable title:	Proposal of new variants of TSO-driven balancing design: documentation and expected results in typical cases
Work package:	WP2.3
Lead contractor:	Risø DTU
Deliverable number:	**D34**
Deliverable title:	Proposal of new variants for day ahead market design: documentation and expected results in typical cases.
Work package:	WP3.4
Lead contractor:	EnBW Transportnetze AG
Deliverable number:	**D35**
Deliverable title:	Proposal of new variants of intraday market design: documentation and expected results in typical cases
Work package:	WP3.7
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Acronyms

- **Activity "c"** refers to the OPTIMATE tasks dealing with "current designs and expected evolutions" (WP2.2, WP3.2, WP 3.3, WP3.6. of DoW)
- **Activity "d"** refers to the OPTIMATE tasks "innovative target designs" (WP2.3, WP3.4, WP3.7 of DOW)
- **ATC** Available Transfer capacity (capacity calculation / provision)
- **BRP** Balance Responsible Party
- **BS** Baltic States: Estonia, Latvia, Lithuania (European Regional Initiative)
- **CEE** Central East: Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia (European Regional Initiative)
- **CSE** Central South: Austria, France, Germany, Greece, Italy, Slovenia (European Regional Initiative)
- **CWE** Central-West: Belgium, France, Germany, Luxembourg, Netherlands (European Regional Initiative)
- **DA** Day Ahead
- **DAM** Day-Ahead Market
- **DoW** Description of Work
- **DR** Demand Response
- **FB** Flow-based (capacity calculation / provision)
- **FG** Framework Guideline
- **FIT** Feed-in tariff (RES-E support scheme)
- **FUI** France, UK, Ireland (European Regional Initiative)
- **GCT** Gate-Closure Time
- **ID** Intra Day
- **IDM** Intra-Day Market
- **IEM** Internal Electricity Market
- **MS** Member State (of the European Union)
- **NC** Network Code
- **OTC** over-the-counter
- **PCG** Project Coordination Group at ERGEG (http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_WORKSHOP/Stakeholder%20Fora/Florence%20Fora/PCG)
- **PV** Photovoltaics
- **RT** Real Time
- **SEM** Single Electricity Market (of the Republic of Ireland and Northern Ireland – term used in relation with the European Regional Initiative)
- **SWE** South-West: France, Portugal, Spain (European Regional Initiative)
- **TSO** Transmission System Operator
- **WP** Work Package
- **XB** Cross-Border

Glossary

Balance Responsible Party (BRP)
Each physical asset considered in OPTIMATE belongs to a BRP, be it participating to the market or not. A BRP has to pay or to receive the imbalance settlements fees as defined in the design of a given area. A BRP belongs to a unique bidding area. In OPTIMATE, a Portfolio and a BRP are synonyms (see Portfolio).

Continuous (organized) market
In a continuous market, bids are matched one by one, although anonymously, as soon as it is possible that is to say when the bid price is greater than the offer price.

DA markets
DA markets includes DA organized markets, DA programmes (alternative wording 'unit commitment') and DA congestion management by TSO. It does not include DA balancing procurement which are described in chapter 6.

Market area, bidding area
In OPTIMATE we use market area to qualify an area with common rules for organised markets, balancing mechanisms and imbalance settlements. A market area stands basically for a country, with some exceptions. In OPTIMATE we shall consider for instance the following:

- Belgium
- The Netherlands
- Germany
- Switzerland
- France
- Italy
- Spain + Portugal
- Denmark

A market area includes one or several **bidding areas.** Those are subsets where the clearing price is unique. For instance, there are several bidding areas in Italy and in Denmark.

Note that in the OPTIMATE simulator, all bidding areas are assumed to be cleared off at DA under a common market coupling (which is currently not yet the case). Therefore Market area and Bidding areas are synonyms in the simulator (but not in this document).

OTC
OTC are any commercial contract with physical delivery or with impact of imbalance settlements, made before or simultaneously to the DA market, but not being part of the DA organised market.

Portfolio
A portfolio represents all physical assets that a given marketer is responsible for in a given bidding area. The portfolio could be an aggregation of load, of thermal, hydro or must-run units and of intermittent generation. It can also be any subset of those ones. In real life, each portfolio corresponds to one (or several) Balance Responsible Parties (BRP) to be considered both by market and by system operators. In OPTIMATE we neglect the influence of those contracts and we therefore, consider Portfolio and BRP as synonyms.

Portfolio bidding (in an organized market)
Portfolio bidding means that the organized market output does not automatically induce any kind of generators' programme (unit commitment) which then could be taken into account by the TSO. The organized market physical output under portfolio bidding is then a price for all participants and volumes for each participant consistent with the common price and the individual bidding curve. In other words, all the unit commitment is done by portfolio managers separately from (and after) the organized market clearing.

PTDF (Power Transmission Distribution Factor)
PTDFs are a formulation to map electricity production changes in different zones to flows between those zones. Since electricity flows according Kirchhoff's law, by using PTDFs (generally written as matrices), loop-flows can be modelled.

Secondary control reserve
According to Policy 1 of UCTE on "Load-Frequency Control and Performance", secondary control makes use of a centralised and continuous AUTOMATIC GENERATION CONTROL, modifying the active power set points and adjustments of generation sets and controllable loads in the time-frame of seconds up to typically 15 minutes.

Simple /complex order (in an organized market)
A simple order consists in a unique proposed quantity at a unique proposed price for a unique time (cf. bid granularity). A simple order can be a stepwise curve where all the steps have the previous characteristics. The allocated quantity of each step may be any value between zero and the proposed quantity.

All orders which are not simple are complex.

Single/dual pricing for imbalance charge
Single imbalance pricing uses a single price for all positive and negative imbalances. Dual imbalance prices charge differently according to negative or positive imbalance of a balance responsible party.

Tertiary control reserve
According to Policy 1 of UCTE on "Load-Frequency Control and Performance", tertiary control uses tertiary reserve that is usually activated manually by the TSOs in case of observed or expected sustained activation of secondary control. It is primarily used to free up the secondary reserves in a balanced system situation. Tertiary control reserve is activated with relation to the predefined timeframe of exchange schedules, e.g. 15 minutes.

Unit bidding (in an organized market)
Unit bidding means that the organized market output induces a piece of generators' programme (unit commitment) to be taken in account by the TSO. These programmes are binding for the concerned equipments as far as no reprogramming happens after this time.

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1. Executive summary

This document describes potential market design alternatives to be considered within the OPTIMATE meta model. The analysis focuses on day-ahead (DA), intra-day (ID) and balancing markets. Design options are described and their potential impact on massive intermittent RES-E market integration is assessed. This leads to an outlook on 'target market designs' which are to be modelled in OPTIMATE: those are expected to increase the efficiency with which existing technical infrastructure – such as generation units and grid capacities – are used to facilitate the integration of intermittent, stochastic feed-in. The idea behind is that physical use of the assets mentioned above has to be adjusted in order to accommodate for the increased intermittent feed-in. Market designs should make sure that this adjustment results in economically efficient market outcomes (i.e. welfare maximisation). Besides specific suggestions for modelling alternatives, surrounding explanations of efficiency problems which stem from practical issues (that are not part of the model) are provided. Those are intended to help interpreting the results of the simulation model when relating them to real markets.

The main results and recommendations for design options to be considered are the following:

- **Timing issues:**
  This relates to both DA and ID markets. For DA markets, the gate closure time and the length of the period to be auctioned at DA are the parameters to vary. One can expect, for instance, that a combination of shortening the period being auctioned in combination with a postponement of the gate-closure time (GCT) can show some beneficial effects for set-ups including large amounts of intermittent generation. Conversely such changes could be problematic to markets with lower intermittent generation, and their operational consequences for market and system operators should thus be investigated. Testing them in the OPTIMATE simulator could help to quantify pros and cons. For ID markets (with a continuous trading mechanism) we suggest evaluating the impact of a postponement of the time before delivery until which trading is still possible (GCT-only effect).
- **Complex bids, negative prices and other features related to dynamic constraints:**
  The availability of complex orders in organized power markets can help to improve the market integration of conventional units with inter-temporal constraints on their operation. They are thus considered as helpful means to increase economic efficiency of the market. On the other hand, complex bids may induce severe feasibility constraints in market clearing algorithms, especially in a coupled set-up. The OPTIMATE simulator could hit those feasibility limits even sooner as it has the ambition to handle the whole process and not only the power market clearing. Therefore a realistic inclusion of complex orders in the OPTIMATE simulator may be limited. Nevertheless any possible progress in this direction will be welcome.

  The allowance of negative prices in power markets could also be seen as reflecting physical dynamic features such as start-up costs. Therefore their allowance should increase reliability of the market's price signals in extreme conditions and is therefore worthwhile to be quantified through simulations.

- **RES-E support schemes:**
  The frameworks defining the rules for market participation of RES-E producers differ heavily across Europe. We suggest to simulate the impact of feed-in tariffs on the one hand and market premiums/tradable green quota schemes on the other hand. The reason is that in the latter cases, RES-E plant operation is subject to some kind of economic dispatch. We expect those incentives to lead to a more economic market integration. Moreover, we do think that it is also important to model the impact of attributing balance responsibility of RES-E to different actors. Obligating each single RES-E producer to keep his account balanced might impose a higher revenue risk and transaction cost on them – in contrast to the case where RES-E imbalances are pooled and attributed to a single party.
- **Market integration / cross border capacities:**
  The efficient usage of cross-border capacities is without doubt helpful for integrating large amounts of RES-E into the electricity market. The designs under discussion for implementation in Europe are already on the table: DA market coupling is therefore to be simulated in the two variants discussed – ATC-based (Available Transmission Capacity) and flow-based.

  Additionally, we propose to assess the quantitative impact of an intra-day recalculation of available capacity – both with ATC and flow-based. Within the intra-day time frame, we encourage to assess different alternatives for rent collection.

  For balancing purposes, we found that it might bring new insights to model not only the cross-border (XB) exchange of regulating energy but also to assess to what extent reserving capacity on interconnectors could increase economic efficiency.
- **Pricing of imbalance settlements:**
  An issue often debated among practitioners and academics is the question whether imbalances should be invoiced to the respective parties on a dual or single price basis, including a penalty effect in the former case. The combination of those choices with the above variants appears to be complex and difficult to anticipate intuitively – we therefore propose to investigate this question.

The considerations concerning the interpretation of the model-results relate mainly to questions such as:

- Prerequisites for liquidity (low barriers to entry, adequate level of freedom such that truth-revelation becomes possible, etc.),
- Optionality of markets (as opposed to mandatory markets) in order to allow for selection between them.

The present deliverable constitutes the unique OPTIMATE “d” deliverable, grouping the three contractual deliverables covering the target design aspects for DA (D34), ID (D35), and Balancing (D23) listed in the table below.

	Deliverable ID	Resp.	Description
Unique «d» deliverable	D34	EnBW	Proposal of new variants for day ahead market design: documentation and expected results in typical cases.
	D35	EnBW	Proposal of new variants of intraday market design: documentation and expected results in typical cases.
	D23	RISOE DTU	Proposal of new variants of TSO-driven balancing design: documentation and expected results in typical cases

2. Introduction

The OPTIMATE project (An Open Platform to Test Integration in new MArkeT designs of massive intermittent Energy sources dispersed in several regional power markets) aims at providing a new tool to assess the features of new electricity market designs.

The OPTIMATE simulator focuses on day-ahead (DA) and intra-day (ID) time frames with special respect to the market integration of intermittent generation. Key points to be addressed are:

1. Impact of RES-E support schemes on dispatch decisions (disregarding long-term characteristics of the support scheme).
2. Imbalance settlement rules and the balancing market – they might influence the behaviour of BRPs – especially if intermittent production is within the BRP.
3. Market design features influencing market liquidity and economic efficiency, such as cross-border congestion management methods, timing issues, etc. The focus is to assess the possible impact along the different allocation time frames (DA/ID/RT).
4. Cost reflectiveness of thermal start-up and other dynamic constraints, as they could be the counterpart of Intermittent generation volatility and therefore play a major role in the overall efficiency of the design;
5. Valuation of flexible resources, such as hydro, peaking units flexible load and flexible intermittent generation, able to provide short-term flexibility.

This report focuses on the description of market design options potentially addressing the above-mentioned key points. It aims at providing a broad survey of the evolutions of European market designs (provided that they are related to the five key points mentioned above) and at describing briefly the most prominent rationales underlying these expected evolutions.

Although this report does not generally state whether a specific evolution could be represented in the OPTIMATE simulator, some preliminary feasibility statements are made all over the document.

The present work is closely interrelated with the OPTIMATE analysis of current market designs performed within Work Package 2 (Real time adjustment of generation and load balance) and Work Package 3 (Day ahead and intraday markets). Moreover, it provides valuable inputs to Work Package 1 dealing with the specifications and modelling of the OPTIMATE simulator.

3. Background and perspectives on target market designs in Europe

3.1. Background

The European energy market in general and the electricity market especially are subject to two big challenges: European market integration in the sense of tearing down trade borders on the one hand and the climate change challenge, namely Carbon on the other hand (Capros, Mantzos 2009). The crucial task is to ensure that the beneficial effects of market integration and liberalization are not offset by the investments necessary to achieve the reduction of carbon emissions and the mitigation of climate-related risks. The overall target is hence the reconciliation of competitiveness and sustainability. The EC chose the acceleration of technical progress as adequate means to mitigate the economic consequences of carbon-reducing actions.

However, the strategic and abstract measures influence the concrete allocation decisions which occur through a market (and where there is no market on the basis of the individual behaviour and interaction of the subjects). Hence, market design, i.e. the rules and mechanisms, is the framework where those allocation decisions occur. The situation of the liberalized electricity market under the influence of heavy intermittent in-feed is a special one since (list not exhaustive):

- electricity cannot easily (= cheaply) be stored like other commodities,
- electricity has to be consumed at the same time it is produced,
- the market has physical limitations such as congested lines, and feed-in at nodes remote to the large power sinks on a grid originally built for power generation close to load,
- forecasts of intermittent electricity production are not as exact as day-ahead programming of thermal units.

(Newbery 2009a)

A central characteristic of intermittent RES-E in-feed is its stochastic character and the difficulty forecasting it. Especially for wind (which is by far the largest intermittent RES-E source), the predictability of actual generation improves closer to real time – meaning the forecast quality is worse one day ahead than 2 hours ahead (Graeber et al. 2010). If load is considered inelastic, the forecast error (the latest unveiling at real time) has to be corrected by dispatchable production units, at least for RES-E production deficits. However, thermal and pumped-hydro storage (PHS) units underlie inter-temporal constraints, which leads to the perception that a pure real-time dispatch of their full capacity might not lead to optimal allocation results.

Today's organized (wholesale) electricity markets in Europe are based on day-ahead and forward contracts, whereas the increasing amounts of wind power is expected to lead to a higher demand of intraday trades and balancing services. To reduce the wind integration costs, those markets should be liquid (Weber 2009). Therefore, this aspect of integration of intermittent production cannot solely be attributed to DA, ID or balancing markets but questions the arrangement of the three of them as a whole. However, one aspect that separates balancing markets from the former two is its asymmetry as the system manager, which is the TSO, is the one who procures and activates reserves.

RES-E producers are incentivised by support schemes which may be tax reductions, feed-in tariffs, market price premium payments or green certificates (EC 2009/28). Feed-in tariffs (FIT) are paid for RES-E fed into the system, basically not reflecting the 'free electricity market' value of the electricity (which depends on the load and production situation). However, this protects the RES-E producer from market price volatility and secures – in addition to the long-term guaranties of the tariff – the investment. Price premiums are payments which are paid on top of the market price. This exposes the producer to market price risks, and does not guarantee dispatch. The third approach is based on tradable certificates, namely 'green certificates'. The producer receives certificates per unit of RES-E produced. Demand for green certificates is established by imposing green quotas on either producers or consumers.

As mentioned above, power grids in member states of the EU were not built to facilitate an integrated European market place for electricity but rather to connect power plants to load centres located close to them. After having allowed for electricity trading, demand for electricity transmission over longer distances has emerged. This is even more true for new technologies (e.g. wind) which cannot be built everywhere but are strongly dependent on meteorological or other conditions specific to certain regions. Electricity wholesale prices in most European countries are equal for a large area, signalling there is no scarce transmission capacity (i.e. considering the grid as a "copper plate"). However, management of capacities at interconnectors between price regions is an issue strongly demanded by EU legislation (EC regulation 1228/2003 and its successor EC regulation 714/2009).

The solutions for the problem of economically signalling congested lines (in the short term) range from nodal pricing (separate prices for each node of the system are calculated) to zonal pricing approaches where the areas considered as non congested are larger. Today, congestion management in Europe is done mainly by explicit or implicit auctions. Implicit auctions take place through market coupling systems which aim at utilizing the cross-border capacities to maximize overall welfare. The focus on congestion management activities today is on day-ahead trades. For this timeframe, the long-term target model for the EU is a single, price coupled market. For feasibility and organisational reasons, second best target models are also mentioned (volume-coupling related models).

Therefore, the discussion about target designs for the EU electricity market concerning each of the market segments (DA/ID/Balancing) is heavily dependent on the RES-E support schemes and the efficient availability of transmission capacity. Although not part of the analysis by the OPTIMATE simulator, long-term incentives of the market design models given should not be neglected. Concerning this point, Newbery (2009b) argues that highly efficient short term price signals may exhibit high volatility, thus discouraging investment because of more uncertain revenues. Hence, the optimal short term solution conflicts with the optimal long term solution – so the overall optimal solution is necessarily a trade-off between short-term efficiency of dispatch and minimum-risk investment.

3.2. Perspectives for the Future

The primal consideration of this paper regarding new ("innovative") target designs is that they can help to facilitate the integration of massive intermittent electricity into the European electric power system. This 'power system' includes not only the physical transmission & distribution grid, but also the generators, the load and the related markets.

Besides the often stated call for new power lines (cf. e.g. dena Study 2005), which is undoubtedly important, the question to be answered in all the situations is the question of efficient usage of the current infrastructure. Efficiency can hence be read as 'cost-efficiency' – meaning that the physical requirements due to increased trade & intermittent RES-E feed in (among other factors) are fulfilled at the least cost possible of electricity production.

In the next paragraphs, some current drivers with respect to market designs at European level are presented. Issues going beyond those current drivers are discussed in chapter 7.

3.2.1. The "Third package"

The 3rd legislative package on EU electricity & gas markets (subsequently abbreviated as '3rd package') was adopted by The European Council in June 2009. Its focus is mainly on integrating the Community electricity markets and therefore on cross-border issues, resp. the harmonisation of the XB rules.
However, there is no special emphasis on RES-E / intermittent market integration – the main concern in this respect is with non-discriminatory grid access of those units.

The implementation of the third package shall be ensured by the interaction between regulators and the concerned network operators: the regulators will collaborate within the Agency for the Cooperation of Energy Regulators (ACER) established by Regulation (EC) 713/2009 and the European TSOs for Electricity within the European Network of Transmission System Operators for Electricity (ENTSO-E) foreseen by Regulation (EC) 714/2009 of the 3rd Package. According to article 8.3 (b) of the Regulation (EC) 714/2009, "ENTSO-E shall adopt a non-binding Community-wide ten-year network development plan" (TYNDP) with the objective to ensure greater transparency regarding the entire electricity transmission network in the Community and to support the decision making process at regional and European level. The first version of the TYNDP was released in 2010.

Moreover, ACER will prepare specific framework guidelines which ENTSO-E will then use to define network codes (NC). These Network codes will then be approved by ACER, likely followed by public consultations. The planned structure and schedule on FGs (framework guidelines) and NCs is documented in the 3-year-Plan ("3a-Plan") created by the EC, both ENTSOs, and the ERGEG. It was presented at the 18th Florence Forum in 2010. The timeframe envisaged by the plan are the years 2010-2012. The 3a-plan is shown in appendix 9.1.

3.2.2. *Further activities*

ENTSO-E
Besides its tasks within the implementation of the Third Package, ENTSO-E carries out several other activities, e.g.: the Market Integration Working Group (MIWG), CWE-Nordic for coupling the whole area including project teams for DA and ID.

CEER (Council of European Energy Regulators)
A recent public consultation of CEER (C09-PC-43) on market integration of wind generation yielded the call of shortening ID-GCTs and, related to that, the creation of ID XB markets where XB capacity is implicitly allocated. There was also strong support for extending balancing regimes over borders to make balancing services less costly.

The Florence Fora
An outline on how the long-term market integration target could be reached was given by the PCG[1] at the 17th Florence Forum in December 2009 (Fig. 1). The abbreviations used in the figure are the same as given above. The figure shows a possible schedule for coupling European electricity markets. The different abbreviations for the markets relate to the so-called European Regional Initiatives (ERI)[2]. The rationale behind this is to let regional initiatives develop their regional integration solution first and then to integrate the regional solutions. Both the average yearly consumption of the markets and the interconnector capacities illustrate the coupling potential resulting in a single European coupled market of more than 3500 TWh yearly consumption.

[1] PCG stands for ‚Project Coordination Group' which was established in the aftermath of the 15th Florence Forum, held in November 2008. It was chaired by the European Regulators' Group for Electricity and Gas (ERGEG) and included participants from various stakeholders, including European power exchanges and TSOs. Its job was to propose a target model to integrate the regional European electricity markets. For further information, please see: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_WORKSHOP/Stakeholder%20Fora/Florence%20Fora/PCG .

[2] The European Regional Initiative was set up in 2006 by ERGEG and aims at speeding up the European market integration process by designating so-called regional initiatives. Those are: BS (Baltic States: Estonia, Latvia, Lithuania), CEE (Central East: Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia), CSE (Central South: Austria, France, Germany, Greece, Italy, Slovenia), CWE (Central-West: Belgium, France, Germany, Luxembourg, Netherlands), Northern (Denmark, Finland, Germany, Norway, Poland, Sweden), SWE (South-West: France, Portugal, Spain) and FUI (France, UK, Ireland). The electricity market of Ireland is denoted as single electricity market (SEM) since it encompasses the Republic of Ireland and Northern Ireland.

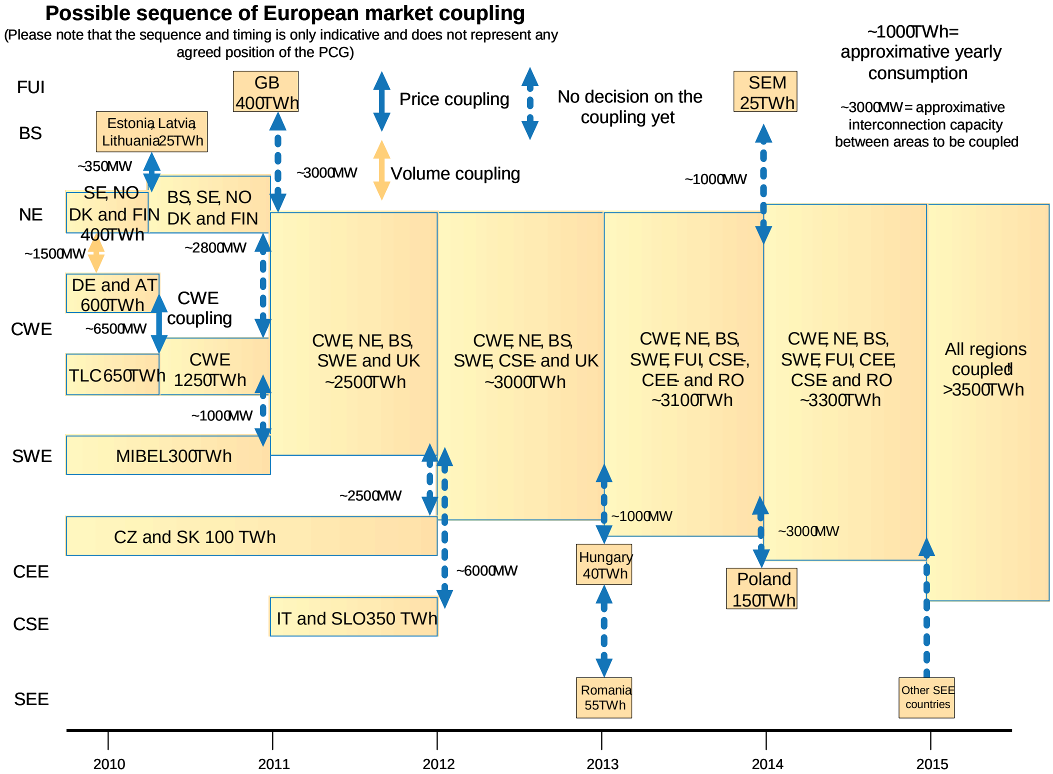

Figure 1: Market integration scenario as proposed by PCG

The PCG was then superseded by the AHAG, the ad-hoc advisory group, which was set up by the 17th Florence Forum. The tasks of AHAG are to support ERGEG in the development of so-called framework guidelines (FG) stipulated by the 3rd legislative package on EU electricity & gas markets

Especially the FG “on capacity allocation and congestion management” shall benefit directly from AHAG work which has project groups on capacity calculation, intraday trading and day-ahead market coupling governance. The overall package implementation process then hopefully leads to a harmonized European framework for market integration projects: a standard set-up of common technical and governance rules which have been shown to be difficult and time-consuming to create within single projects.

4. Day-ahead market design options

4.1. Market Organisation

The current standard in Europe is the so-called power exchange markets with either portfolio bidding or with unit bidding. Other set-ups (e.g. power pools) are implemented in other parts of the world but are not considered within OPTIMATE (see appendix 9.2 for a comparison of exchanges and pools).

Exchange markets are generally optional, i.e. over-the-counter (OTC) trading is possible. For all market participants, no matter where they trade inside their bidding area, the link with physics is done by relating them to a balancing responsible party (BRP). They are then subject to imbalance settlement rules to ensure they have an incentive to physically implement their schedules.

An exchange market allows TSOs and market operators (MOs) to be separate entities with separate functions. TSOs are in charge of system security including assessment of risks related to physical hazards and contingencies, while market operators are in charge of market reliability related to liquidity, development of derivatives, complex bid types, etc.

There are two variants of Power Exchanges:

- **Power Exchanges market with portfolio bidding**
  In such case the market participant is not required to disclose his underlying production programmes to the market operator when submitting his bids. This information is necessary for TSO security assessment, and it happens some time after the price revelation. So the market participant may rearrange his DA unit commitment to take clearing prices into account before having to submit the physical schedule to the TSO.

- **Power Exchanges market with unit bidding**
  This model is an adaptation of pool designs to a power exchange design. Under unit bidding, the bids specify the units which would deliver the quantities specified in the bid. The aforementioned unit-related information can be considered as a preliminary programme since the market participant can rearrange his dispatch OTC (as the exchange is an optional market). Complex orders in unit-bidding exchanges are designed in a different way (typically more complex) even though they aim at representing the same general plant characteristics (ramping constraint, start-up costs, component ageing and technical risks due to fast ramps). Furthermore, monitoring bidding behaviour of certain units / BRPs does appear to be easier under unit bidding thus allowing for more regulatory influence on the market.

4.1.1. Characteristics of European DA markets

In all countries considered within the OPTIMATE project (see list in the Glossary), the DA markets are power exchanges which can be considered as the European standard (the following summary stems from the description in Barquín et al., 2010). Only Spain, Portugal and Italy require unit bidding; all others allow for portfolio bidding. In Belgium, France and the Netherlands, continuous day-ahead markets exist which are however not involved in any implicit allocations of XB capacity. The bidding areas are countries in general.

Typically, block orders are possible, sometimes market participants can even configure their own complex order types.

Gate-closure times (GCTs) are around noon and all 24 hours of the next day is cleared off then.

XB capacity is partly being auctioned explicitly some hours before GCT of the organised, discrete DA markets, partly being allocated implicitly.

The implicit allocations of XB capacity currently in operation are:
- Tri-Lateral-Coupling (TLC) between Belgium, France and the Netherlands (price coupling),
- Germany-Nordic by EMCC (European Market Coupling Company) between Germany and DK1/DK2/SE (volume coupling),
- MIBEL, price coupling (market splitting) between Portugal and Spain.

It is planned to replace TLC and Germany-Nordic by the so-called ‘CWE Interim Tight Volume Coupling solution’ (ITVC), where CWE stands for Central-Western covering Belgium, France, Germany, Luxemburg and the Netherlands. The transition is planned for fall 2010. Within this set up, a volume coupling will first be done between CWE and Nordic countries, before each regional price coupled market clearing is made. This configuration is also known as “dome coupling” (cf. EuroPEX, ETSO, 2009).

4.2. Design options

The target for future market design is a **single price coupling at least on a broad regional basis**: one single matching algorithm determines the prices in each market area (equal if no congestion), accepted bids & offers.[3] Furthermore the XB transfer volumes are determined.

4.2.1. Gate Closure Times & Length of Period to be settled simultaneously

One of the most obvious design options of Day-Ahead markets is the timing issue. Not only the gate closure time could be changed, but also the duration and granularity of the delivery time auctioned simultaneously. This is however closely linked to the use of complex bids such as block bids which are supposed to be supporting a stable equilibrium (cf. Ockenfels et al. 2008)[4].

[3] Price coupling vs. volume coupling is explained in chapter 4.3.1.

[4] Complex bids are often used to account for inter-temporal constraints in thermal plant dispatch. A complex bids covering 24 hours is for example only possible if the duration auctioned simultaneously covers 24 hours.

4.2.2. Mitigating the exercise of market power

Especially in early stages of electricity market liberalisation, there has been plenty of discussion on market power in electricity markets. (cf. e.g. Stoft 2002). As counter-measures, price caps / floors, the mandatory use of the market and further heavy regulation have been proposed and are partly established.[5]

4.2.3. Enhancing market liquidity

The liquidity of markets is a property often emphasised. It is important for the functioning of a competitive market in general (cf. Batlle et al. 2007) and for the ability of a market to efficiently take up large amounts of intermittent energy production (cf. Hiroux, Saguan, 2009). However, liquidity is more a concept than a technical parameter that can be measured exactly. Most often, it is somehow characterised as the ability of markets to take up volumes of numerous participants without significantly changing the price (cf. Weber 2009) and allowing for trade at virtually any time (in case of continuous markets; cf. Grossman, Miller, 1988). Therefore, liquidity is considered as a key-premise for (cost) efficient integration of renewable energy penetrating the markets while maintaining the fundamental price.

4.3. Congestion Management / Physical Layer

4.3.1. Current Congestion Management practices

Most European Electricity Markets are operated as “copper plates”, where internal congestions are relieved by curative re-dispatch of production units. The reason for such situations is that transmission capacity is limited. Such transmission capacity limitation is also true for the capacity connecting two national electricity markets.

For the market based allocation of XB capacity, there are basically two options.

The most straightforward one is the **explicit allocation** by the use of auctions where traders have to procure XB capacity prior to arbitraging the neighbouring markets. Typically, the day-ahead auction of XB capacity takes place before the gate closure of the organised day ahead markets, making the capacity procured in such a way an *option* on a power price spread with the capacity price as *strike*. Although this approach is easy to implement and most common at European borders, it often leads to adverse flows. Adverse flows are commercial flows from a high price area to a low price area which is economically pointless.

To improve the allocation of XB capacity, **implicit auctions** have been proposed and are partly in use. Implicit auctioning means that a central matching unit uses bids and XB capacities available to calculate the socially optimal XB transfer schedule. Depending on whether this central unit calculates the prices in all regions or only submits unlimited bids to the connected PXs, the terms **price coupling or volume coupling** are used.[6] Implicit auction of DA XB capacities is currently (September 2010) in operation between France, Belgium and the Netherlands (price coupling), Spain and Portugal (price coupling) and between Germany and Scandinavia (volume coupling).

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5 Although not in the focus of OPTIMATE, literature suggests that market power issues can be successfully tackled by forward contracting (cf. Allaz, Vila 1993 and Wolak, 2007).

6 However, a central unit allocating all XB capacity of a region represents a monopoly function. Likewise, making access to the coupling function exclusive to some PXs, implicitly makes them a monopoly supplier of XB capacity (cf. Meeus 2010).

Prior to the actual allocation process, both capacity and bottlenecks have to be defined. As mentioned above, bottlenecks are often declared at the borders between historically grown market areas. Therefore, congestions can be disclosed at all concerned connections or at countries / areas borders only. The different calculation methods are (coordinated) ATC and FB. “Coordinated” ATC means calculating the ATCs of multiple adjacent borders within one model resp. selecting the largest capacities being consistent with the output of multiple models covering a larger area. There are different degrees of coordination, according to the size of the ‘larger area’. Examples of such calculations are the ‘German C’, the ‘Swiss Roof’ and the ‘Italian Roof’ (cf. EnBW Transportnetze AG, 2009 and Duthaler, 2007). Beyond those coordinated calculations, the next step would be the use of common grid models, which would provide an even more integral approach.

In case of a FB calculation, a PTDF (Power Transfer Distribution Factor) matrix is calculated which allows for appropriate consideration of loop-flows.

4.3.2. Resulting Prototype Congestion Management Concepts

The prototype concepts for congestion management are (in ascending order of complexity):

1. **National markets with explicit XB capacity auctions** (ATC) some hours before energy markets gate closure.

2. **Coupled national markets with implicit XB allocation** (either FB or ATC).

3. **‘Zonal’ pricing with the option of splitting national markets into different zones** to internalise redispatch cost due to structural internal congestions.[7]

4. **Nodal pricing**: Market clearing under full consideration of the whole network, i.e. bidding and energy pricing at each single bus-bar of the network.

The development in Europe is clearly to let behind explicit auctions and set up market coupling in day-ahead (cf. 0). Explicit auctions might remain valid for long term allocation, but this time frame is not simulated in OPTIMATE. However, both ATC and FB market coupling approaches can be simulated within OPTIMATE.[8]

[7] In the Flow-Based version of a coupled national market implicit allocation, the presence of internal congestions are almost internalised in each national market price (assuming that the internal congestion split the national market fairly close to its geographical border). However in such case, the redispatch needed to guarantee firmness, if any, is external to the DA coupled clearing process. This is then of course not due to lacking price signals but caused only by contingency, not structure.

[8] Theoretically, introducing explicit auctions could be considered, but this would require to estimate the uncertainty traders have on spot energy prices when bidding for capacity. The result would then simply reflect the estimated uncertainty which would not add value. The model itself cannot be expected to be capable of appropriately estimating this uncertainty.

Nodal Pricing is usually not considered as an option in the EU, although this model has some support – especially among academics. Basically it is argued that nodal pricing would induce significant transaction costs compared to their benefits, and that it would not bring progress on cross-border issues which are regarded as the key point in Europe, unless a somehow unrealistic centralised European TSO (or ISO) would be created. Moreover, the feasibility of Organised Intra-Day markets in the nodal scheme is questionable and has not been addressed anywhere to our knowledge. Finally the nodal scheme does not provide any sound long term locational signals, at least not straightforwardly, e.g. for power and/or network development which is seen as the top priority for the electricity sector. Therefore, we mention this approach but do not consider it as an option within this report.

4.4. Conclusion: DA market design options

The basic design options of DA markets can be summarised as follows:

Design option	Expression
Complex bid types	Types of complex bids available
Price floors / caps	Level of floors / caps
Timing	GCT, length of period to be auctioned
Bid Granularity	Length of single delivery period to be allocated
Coupling: Bidding areas	Size and location of bidding areas
Coupling: Capacity Calculation	Level of coordination, i.e. use of common grid models
Coupling: Capacity Modeling	ATC / FB
Regional differences	Neighbouring zones with different DA designs

5. Intraday market design options

5.1. Characteristics of European ID markets

ID markets exist in all countries studied within OPTIMATE, except for Switzerland. They do allow for the trade of hourly deliveries, except for the Netherlands where not only hours but also 15min-blocks may be traded. The European ID markets considered in OPTIMATE are mostly continuous markets, with the exception of Spain and Italy, where discrete ID auctions are held (cf. Barquín et al. 2010). The continuous trading consists of an order book collecting incoming sell/buy orders executing them as soon as they are executable (i.e. a sell limit of an order is lower or equal than a buy limit of another order). Some markets do even allow for block orders being entered into the ID market system.

Typically, trading at the ID market is possible until roughly one hour before actual delivery.

As of now, XB capacity is not being allocated implicitly within those ID markets. However, XB capacity allocation is available on ID in most countries. This is generally done through explicit mechanisms, either by discrete auctions or first-come-first-serve arrangements where the latter is the predominant one. Such an XB First-come-first-serve arrangement combined with continuous markets can indeed be seen as a proxy towards implicit continuous trading platform, see 5.2.3.

5.2. Design options

5.2.1. Continuous vs. discrete Auctions

As observed, ID markets can be continuous trading platforms or be facilitated by a number of discrete auctions. The theoretical difference between the two approaches is the valuation of immediacy (cf. Grossman, Miller, 1988): in continuous markets, the expected time required to execute an order is significantly lower than under a series of discrete auctions if one has to wait until the next auction.

Concerning future concepts, the focus in Europe seems to be on continuous markets. This option is the only one broadly discussed in TSO projects. The reason for that is that discrete auctions would have to be synchronized in case of a coupling, and that they are potentially less flexible, especially with regard to the requirements of future power technologies.

5.2.2. Moving end-of-ID closer to Real Time

Moving the end of the trading period closer to real-time is often discussed as means to improve the market integration of intermittent RES-E production since the forecast of their production often becomes more precise, the closer delivery is. This may decrease the use of valuable reserve energy.

5.2.3. *Coupling: mechanism options*

The model most often discussed (cf. ETSO 2008, CWE TSOs 2010) is based on matching not only bids within a local order book but also across borders if capacity is available. This model, often called implicit continuous trading platform, is illustrated in Figure 2. The respective local order books relate to hubs 1,2. In the figure, stylised aggregated supply / demand curves are indicated. Since all matching orders are immediately cleared off, the curves of a single hub do not intersect. However, if they do intersect across the border and if there is free capacity, their bids can be matched across the border. It then would also be possible to collect congestion rents. With respect to rent collection, there are basically 2 options:

- A pay-as-bid mechanism: all bids matched would be cleared with their bid price. The summed spread would then be collected as rent (diagonally dashed area with white background in Figure 2 – labelled as 'alternative 1').
- A pay-as-cleared mechanism: all bids matched are cleared off at the same price at each hub. The rent is then calculated as the spread of the last bids accepted times the XB capacity used to match the bids. This option is labelled as 'alternative 2' in Figure 2.

The concrete variants all share a central element, the so-called "Congestion Management Module" (CMM). This module basically manages all XB ID capacity available and allocates them to the entities requesting it. The concepts differ then more in governance-questions.

However, both pure ATC and FB could theoretically be implemented by the CMM.

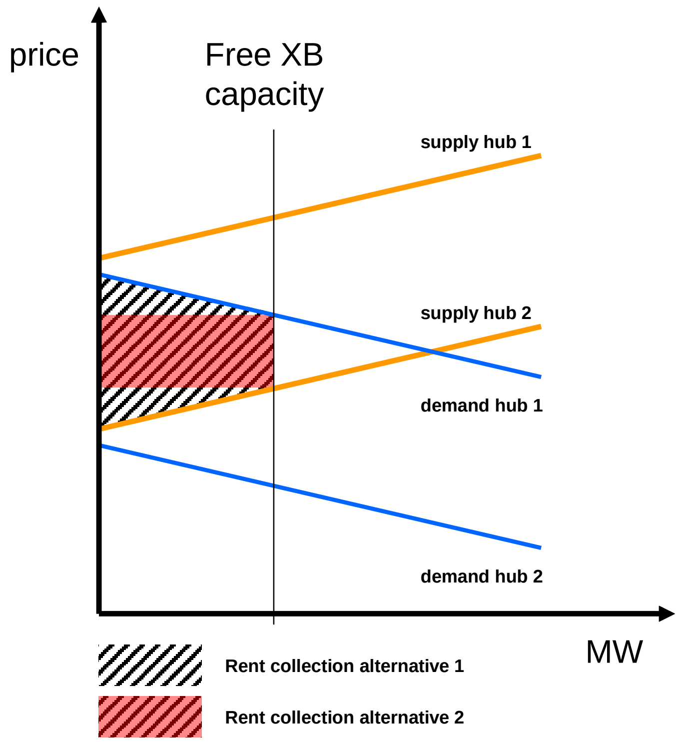


Figure 2: Principle of implicitly allocating XB capacity on the Intraday market. Diagram adapted from CWE TSOs (2010).

Though coupling of synchronized repeated ID auctions seems possible, it is unlikely that this variant will be realised. This alternative would not only require to change the majority of ID markets in Europe to a series of discrete ID auction sessions. Under this assumption, it would be more probable that if different ID allocation mechanisms remain, capacity between those markets will not be allocated implicitly.

5.3. Conclusion: ID market design options

The basic design options of ID markets can be summarised as follows:

For sequential auctions:

Design option	Expression
Complex bid types	Types of block-bids available
Timing	Times and number of the auctions, length of period to be auctioned
Bid Granularity	Length of single delivery period to be allocated

For continuous allocation:

Design option	Expression
Complex bid types	Types of block-bids available
Timing	Start of ID after DA gate closure, end of ID before real-time,
Bid Granularity	Length of single delivery period to be allocated
Coupling: bidding areas	Size and location of bidding areas; these be likely consistent with DA ones
Coupling: Capacity Calculation	Both level of coordination and frequency of updating the calculation
Coupling: Allocation mechanism	Free of charge (FCFS), collecting rents (pay-as-bid), collecting rents (pay-as-cleared)
Coupling: Capacity Modeling	ATC / FB

6. Balancing design options

This section deals with possible options for balancing designs. They can be separated into rules for imbalance settlements and regulating power markets. The latter ones are also known as balancing markets, but are called regulating power markets here for distinction from imbalance settlements. These rules regulate charging of the regulating power market costs either to imbalanced BRP or even to other parties. An extensive overview of current designs is provided in the report “Current designs and expected evolutions of Day-ahead, Intra-day and balancing market/mechanisms in Europe” of the OPTIMATE project (Barquín et al., 2010).

During the actual hour of operation, imbalances in real power occur when demand, supply and cross-border transfers schedules deviate. Schedules may result from trading at organised markets, such as the DAM (Day Ahead Market) or the IDM (Intra-Day Market) as well as from bilateral agreements (OTC). Subsequent to the latest time allowed for nomination of schedules to the TSOs, no more trading can be used to adjust schedules. The balancing responsible parties (BRP) not fulfilling their plans are affected by imbalance settlement procedures. If there is a net imbalance of the whole system, the TSO acts as a single buyer (or seller) on the regulating energy market. Due to the technical and physical complexity involved, the regulating power market is fully centralized even in liberalized electricity industries. It is the task of the TSO to maintain real power balance and, thereby, system balance by means of upward and downward regulation. All participants in regulating power markets are called regulating power providers. Typically, these are flexible power plant operators, flexible demand-side aggregators, or a combination of both.

Rebours et al. (2007b) distinguish a number of possible procurement methods, namely:

- Compulsory provision: A certain class of connected units is required to provide the requested service
- Bilateral contracts: The TSO engages in bilateral contracts with unit operators
- Tendering mechanisms: The TSO tenders the demand for a standardised regulating power market product over longer time horizons (> 1 week)
- Spot market: The TSO organises tenders so regularly (< 1 week) that it can be considered a spot market

Regulating power market participants may place offers and bids that can then be called upon by the TSO. The amount of balancing energy required[9] in one particular hour of operation is not known *ex ante* but contingent on the actual physical state of the electricity system.

In the following paragraphs about design options, we start by having a look at imbalance settlement schemes. Afterwards, we turn towards procurement and charging of regulating power – namely tertiary reserves, as primary ones are ignored and secondary can be modelled as a special case of tertiary reserves. Different pricing scheme options and possible cross-border exchange issues will complete this chapter.

[9] The requirement corresponds to the max energy needed to counter-balance any sudden hazard up to the level of risk to which the TSO is committed by regulation. This level differs between one area to the other.

6.1. Imbalance settlements

There are various designs currently dealing with settlements of imbalanced BRP, and the discussion about which should be the European target is widely open (Vandezande et al., 2009). Such choice has very significant effect on marketers, especially at ID, as a portfolio can always choose between being imbalanced or buying/selling to rebalance in the ID market (providing that this market is liquid enough). Therefore expected imbalance prices are perfect arbitrage value to the ID market, and possibly also to the DA one[10]. The different designs are then detailed in this section.

6.1.1. The single price system

(e.g. Germany, Nordic market applied to load)

Under a single price system, a BRP imbalance that is in line with the overall system imbalance is charged the marginal price for correcting this. In the case of a short BRP and system, this corresponds to the price of upward regulation (P_u). If both are long, the price of downward regulation (P_d) sets the level. If the BRP's deviation is opposite to the system deviation, the respective units receive the price-setting price (Table 1).

Table 1: Imbalance settlement through a typical single price system

			System imbalance	
			Negative (the System is short)	Positive (the System is long)
BRP imbalance	Negative (BRP is short)	BRP has to pay (positive sign)	$+P_u$	$+P_d$
	Positive (BRP is long)	BRP is paid (negative sign)	$-P_u$	$-P_d$

P_u stands for Imbalance Upward Price and P_d stands for Imbalance Downward Price. Both variants, i.e. marginal or weighted average, could be implemented.

This system has a mixed incentive on BRP to keep balanced: an incentive when their imbalance contributes to the system imbalance (malus case); a reverse incentive when their imbalance helps the system to rebalance (bonus case). The question which of the bonus and malus effect is dominant is unclear, as BRP can hardly anticipate whether the system will be long or short.

The combined regulating energy market plus single-priced imbalance settlements is a zero-sum game for the balancing market operator (i.e. the TSO), therefore no periodic adjustment is needed to offset the game.

6.1.2. The dual price system

(UK, France, Nordic market applied to generation)

Under this dual price system, a BRP imbalance is charged/paid the DA market price if its own imbalance helps the system to rebalance, and an imbalance price with a penalty effect if its own imbalance contributes to the system imbalance (Table 2).

[10] Imbalance prices are less easy to forecast at a day-ahead time interval

Table 2: Imbalance settlement through a typical dual price system

			System imbalance	
			Negative (the System is short)	Positive (the System is long)
BRP imbalance	Negative (BRP is short)	BRP has to pay (positive sign)	$+P_u$	$+P_{DA}$
	Positive (BRP is long)	BRP is paid (negative sign)	$-P_{DA}$	$-P_d$

P_u stands for Imbalance Upward Price. It is usually higher than P_{DA}. Depending on the design variant, it could be the maximal price of upward balancing offers accepted at this hour, or it could be the weighted average of them times a coefficient (1+K).

P_d stands for Imbalance Downward Price. It is usually lower than P_{DA}. Depending on the design variant, it could be the minimum price of downward balancing bids accepted at this hour, or it could be the weighted average of them times a coefficient (1+K). The asymmetric incentive effects are discussed in the following section.

6.2. Incentives from imbalance settlement setups

Single price systems do not have a penalty component. That is why they provide symmetrical bonus/malus characteristics for BRP. Therefore, it tends to be good even for smaller RES-E market participants. A single price imbalance settlement scheme is revenue-neutral for the managing TSO. Only a possible capacity availability component might interact with network tariffs (see following section).

The dual price system has a strong incentive on BRP to keep balance in all situations, as they are always exposed either to a malus or to a neutral scheme in case they are imbalanced (and they can hardly anticipate whether the system will be long or short). Vandezande et al. (2009) elaborate that the day-ahead price remuneration mechanism in the dual price scheme is argued to keep market participants from gaming (guessing the right direction of the imbalance), but do not see this as a valid argument. However, there is evidence that the bonus and malus effect can be optimised with strategic considerations for wind power operators (Zugno et al., 2010). In systems with high wind power penetration, it is likely that their deviation is in line with the overall system deviation.

Furthermore, the dual pricing scheme favours liquidity in DA markets, due to the incentive for BRP to be balanced: a marketer who waits for the balancing market for supplying (resp. demanding) its power is never paid more (resp. never pays less) than P_{DA}.

The combined regulating power market plus imbalance settlements is not a zero-sum game for the balancing market operator (i.e. the TSO), therefore a periodic adjustment happens to offset the game.

A central difference between those schemes is that the two-price system is not a zero-sum game for the TSO that need periodic adjustments of the balancing-imbalance account to equalize it, and might affect transmission tariffs. Thus, it can lead to a discriminating wealth transfer between different consumer groups. These asymmetric charges and possible penalties can lead to advantages for large units because internal netting becomes more attractive. Variable RES-E units have therefore a stronger incentive to be aggregated in larger units than under a single price regime.

In conclusion, a single price scheme seems more beneficial for variable RES-E units that are balancing responsible.

6.3. Reserves procurement

6.3.1. Capacity & energy Contracts vs. Energy-only balancing markets

An important characteristic of regulating power markets is to what extent they are priced on a combination of capacity (MW), capacity and energy basis (MW & MWh) or on an energy-only basis (MWh).

Capacity-only is mainly applied for the remuneration of primary and secondary regulating power and thus, not in the scope of this report. We will therefore focus on capacity and energy and energy-only models.

Exemplary practice for tertiary reserve (also called minute reserves) is as follows:

- Energy contracts with availability compensation: regulating power market participants conclude a capacity contract with the TSO (frequently based on a tendering procedure). This contract imposes the obligation to place regulating power bids within specified time intervals on them. As a financial compensation for their availability during these periods, market participants obtain a fixed payment for capacity and, additionally, an energy payment upon activation of their bids.

- Energy-only basis: balancing market participants submit regulating power bids with price-quantity pairs whenever they find it lucrative. In return, they receive solely an energy payment upon activation of their bids. However, under such set-ups, there has to be a mechanism ensuring that enough bids are submitted and that gaming is prevented. This may – for an example – be a system where the availability of units is monitored and bidding becomes mandatory in case the unit is available.

Prices for tertiary regulating power depend on the activation likelihood due to arbitrage considerations in comparison to DAM and IDM. If reserves are activated only rarely, the energy price can be expected to be much higher in the tertiary reserves market. For the combined energy/capacity tendering procedure, the TSO could weight capacity and energy prices in the tendering process. Some market actors might strive for low capacity prices and high energy prices, hoping for some windfall gains without being activated. Others might go for high capacity prices and low energy prices, expecting frequent activation.

An overall evaluation between the benefits of capacity & energy contracts or energy-only contracts is hard to make. In both cases, bidders can incur the same incomes. The effects depend on the regulatory environment. As possible justifications for capacity payments, Vandezande et al. (2009) name e.g. high volatilities in the energy price component and respective risks, non-convexities due to start-up costs and directly regulated balancing prices.

6.3.2. Auction methods in regulating power markets

This sub-section discusses the price basis for balancing services (MW, MWh or a combination of both). Now, we turn to auction methods – i.e. how the price can be determined in tendering and spot market auctions. Two major auction methods can be distinguished:

- Marginal bid pricing: this approach is based on a uniform-price action, i.e., all activated suppliers obtain the price of the marginal bid. This generates an extra profit for suppliers that have submitted bids at lower prices. Such a pricing scheme requires a clearing. It might be applied to balancing capacity only, as balancing energy is called continuously and not through clearings. This is why the application of uniform pricing for activated energy might be difficult especially when an area of multiple TSOs uses a common merit order list, as it is the case in Germany.

- Pay-as-bid pricing: by contrast, the pay-as-bid auction (discriminatory auction) constitutes a clearing mechanism under which each supplier receives the price they bid. In practice, balancing parties are most appropriately activated successively, starting with the party with the lowest bid (given no internal network constraints are against this).

While pay-as-bid pricing seems to keep costs to BRP lower, there is a gaming incentive to guess the price of the marginal bid. This strategy maximises actor's profits. In a perfect market, both auction mechanisms thus lead to the same results. An advantage of marginal pricing is that a homogenous good, e.g. regulating power for a certain time period, is remunerated at one price instead of several different ones.

6.4. Cross-border exchange of reserves in balancing markets

In a synchronous system, primary reserves are procured collectively among all connected TSOs. Secondary and tertiary reserves are also a predominantly national topic due to their activation time. However, some cross-TSO-border exchange systems are already in operation.

Whenever a) imbalances of neighbouring countries are opposite and/or b) regulating power prices differ, reserving a certain share of cross-border transmission capacities for this purpose might be justified in certain constellations (Schröder 2009). The same holds for intraday capacities. Thus, 90% of the commercially available transmission capacity could be sold via day-ahead trading, 5% via intraday trading and the remaining 5% via balancing.

The stated numbers are exemplarily. Benefits of such a mechanism could mainly be due to the fact that neighbouring countries have different generation structures and possibly dominant players in the intraday and regulating power markets. Thus, the spread between day-ahead and real-time prices can differ among countries. Such a mechanism could help in avoiding balancing power price peaks in single zones with high imbalances, as balancing power from a neighbouring country can be imported: for example, a thermal-dominated system could benefit from having permanent access to its neighbour's hydro-dominated regulating power market. This effect needs to be weighted with the opportunity cost of not using the capacity day-ahead at all times. However, in a system with a large share of RES-E, such a scheme would facilitate the reciprocal levelling of RES-E from a large region, covering several TSO zones. Nowadays, the delayed arrival of a meteorological low-pressure area for a few hours causes down-regulation in some zones, while up-regulation is necessary in neighbouring zones. Integrated intraday and balancing markets, possibly with a reserved share of available cross-border capacity, could mitigate this problem. However, more research needs to be done on this topic.

Within Europe, there are currently three existing projects for the cross-border exchange of balancing energy: The French-UK "BALIT" (Balancing Inter-TSO) system, the Nordic system and the German Grid Control Cooperation (GCC)[11]. The main principle of those systems applied to work across congested borders is the same: If there is spare transmission capacity, and it is economically beneficial to use balancing energy bids available in the other TSO area, a cross-border delivery of regulating energy is performed. The level of integration differs, the GCC e.g. allows not only for a common merit order list, but also for common dimensioning (but does not depend on it – this feature is not mandatory to be used by all parties). The BALIT mechanism is a so-called TSO-2-TSO system, representing an agreement between two TSOs on regulating energy bids pooling. The Nordic approach can be considered as a multi-lateral TSO-2-TSO approach, since it covers several market areas within different TSO areas.

6.5. Enabling RES-E/DR to participate at the regulating power market

As BRP are used in all European designs, RES-E and DR always participate implicitly to DA and ID market, as well as to imbalance settlements, through the BRP in charge of them. When no BRP is in charge of them, the TSO is implicitly committed to act as their BRP.

Therefore the question focuses on whether RES-E and DR could or should participate in regulating power markets as regulating power providers. In the medium term, the strong increase of variable RES-E generation necessitates adapting regulating power markets to their rising penetration levels.

Regulating power markets have a number of technical restrictions, such as minimum capacity and organisational requirements (such as the presence of a contact person). This fits rather the requirements of conventional large-scale units than variable RES-E units.

[11] German term: Netzregelverbund, abbreviated as 'NRV'

Organisational and procedural evolutions to accommodate for RES-E units within the market for ancillary services might thus be beneficial. In this course, the definition of availability might be reconsidered for certain sub-markets of ancillary services:

- A large share of dispersed intermittent generation units can statistically show that it can provide down-regulating power also over longer time horizons. For up-regulation, the situation is more difficult for them.
- A large share of price responsive load can show that it can provide up-regulating power.
- Some specific price-responsive load, such as electrical vehicles, could provide both up-regulating and down regulating power.

Such considerations should be made with care in order not to ridicule the purpose of last-resort availability. In order to keep costs of regulating power procurement as low as possible, the procurement amount could be made dependent on the expected market share of certain variable RES-E generators. The underlying assumption is that a higher share of variable RES-E in the market leads to a higher level of necessary reserves, and this assumption has yet to be proven for all cases. If it holds, the demand for regulating power due to a certain RES-E source increases simultaneously with its market share – and thus, when its ability to provide positive and negative regulating power is highest.

6.6. Conclusion: Balancing market design options

Design option	Expression
Imbalance settlement	Symmetric single price scheme vs. asymmetric dual price scheme
Regulating power bid types	Energy-only or combination of capacity and energy prices in some sub-markets
Timing	Times and number of the auctions, length of period to be auctioned
Pricing method	Pay-as-bid vs. marginal pricing
Coupling: Zones	Zones can be coupled if DA and ID markets are also integrated

7. Open innovative issues

7.1. Introduction

In the following sections, market design characteristics and their impact on economic efficiency with special respect to the integration of RES-E will be discussed. The design alternatives and related rationales exhibited here go beyond the options listed in chapters 4, 5 and 6: they cover timing issues, the requirement of complex bids to accommodate for technological specificities, RES-E support schemes influencing RES-E dispatch decisions and questions of liquidity and optionality of markets.

7.2. Time(s) of market clearing

7.2.1. Timing factors

The current market design which is based on historical development does not necessarily constitute an optimal market design for the future, with a larger share of variable RES-E. The following explanations take the day-ahead market as an example, although most of the arguments apply also to markets closer to delivery. The argumentation builds on the assumption that the main power market should be 'RES-E friendly' and that all later compensation measures, e.g. in intraday markets, are linked to financial losses due to valuable (and therefore costly) flexibility, low liquidity etc.

Figure 3 gives a conceptual overview of the main time determinants in power markets. The illustration is based on the current status for day-ahead markets in most European countries. Demand needs to be covered over one day, reaching from hours α to β (typically 1 to 24). This is the *trading period length*. The other main time determinant is the *gate-closure horizon*: it is the distance between final submission of all bids (GCT, denominated as 0 in the figure) at the power exchange and the first hour of delivery. Another aspect illustrated in the figure is that forecast errors from variable RES-E generation (ΔRES-E) increase with time distance. Forecasts are the better, the sooner the intermittent production to be forecasted is. Quantifications of this effect for wind power can be found in the literature reviews by Giebel et al. (2010), Graeber et al. (2010), Monteiro et al. (2009) and Weber (2009).

Figure 4 shows the effect of shortening the gate-closure horizon. Obviously, this has an impact on power plant operator's planning, as a very short gate-closure horizon might limit upstart and ramping decisions. Our point in this context is that a shorter gate-closure horizon will decrease the consequences of forecast errors. With regard to wind energy, this argument has been discussed and quantified by Holttinen (2005).

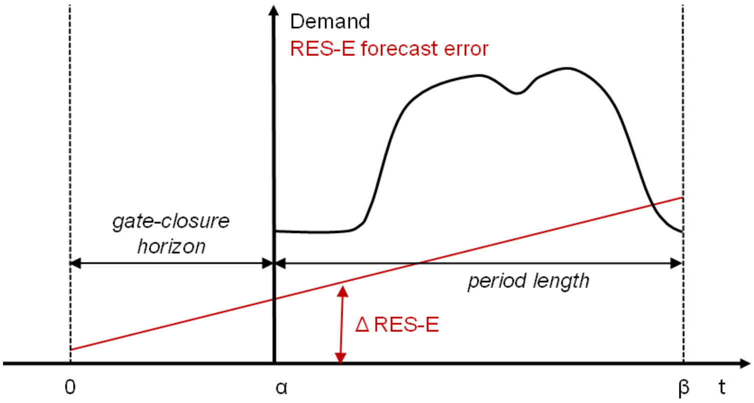


Figure 3: Time determinants in power markets

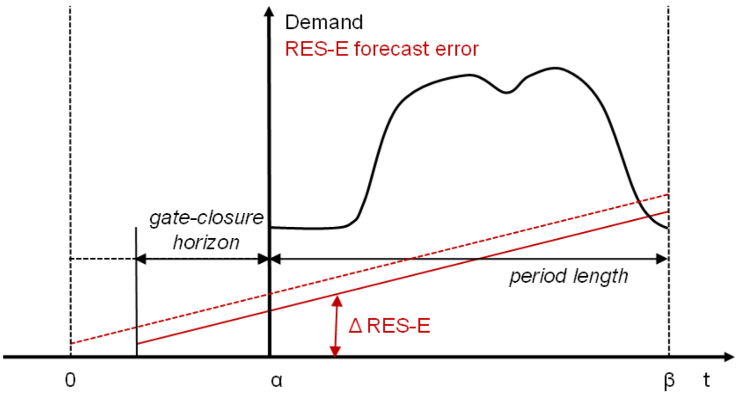


Figure 4: Time determinants in power markets - Changing the gate-closure horizon

A variation of the trading period length is shown in Figure 5. In the graphical example, the trading period length is cut in half (12 hours). Keeping a gate-closure horizon of e.g. 12 hours, this means that at 12am, the 12 hours from 12pm are scheduled and vice versa. In comparison to the base case, where the period reaching from 12 to 36 hours ahead is computed, this offers the advantage that forecast tools only need to provide reliable results on a shorter time horizon. Instead of 36 hours, the maximum look-ahead time is now reduced to 24 hours. This in turn leads to a lower adjustment requirement due to the shortened look-ahead time as sketched in the figure. But this will inversely make the generation scheduling more difficult for the generators with significant upstart and ramping constraints.

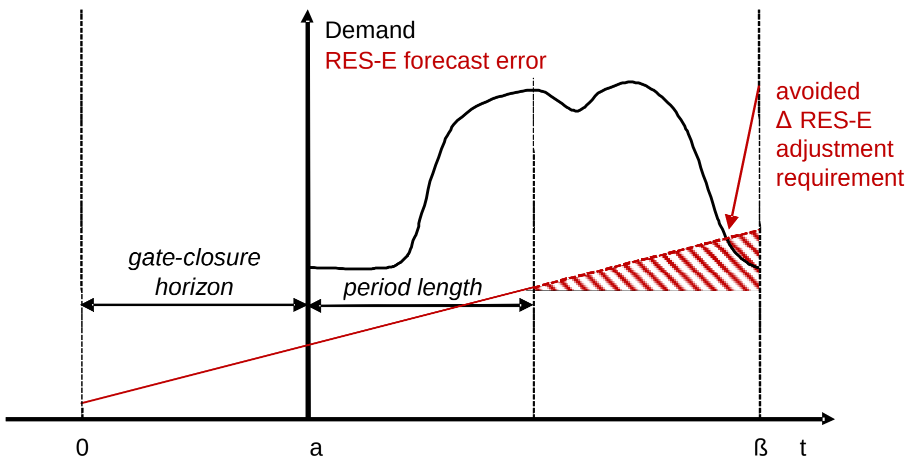


Figure 5: Time determinants in power markets - Changing the trading period length

Figure 6 is a more complex picture than the previous ones. Instead of shortening the gate-closure horizon or trading period length, these two are merely moved. As an example, a trading period length could reach from 6am to 6am, instead of being identical with calendar days. The gate-closure time could be moved analogically, e.g. from 12pm to 6pm. The effect is primarily similar to shortening the gate-closure horizon: in peak demand hours, the forecast error of RES-E is reduced (dashed red line to solid red line).

As a next step, the price for correcting the forecast errors enters the discussion. This price is the price of flexibility between GCT of the discussed market and real-time. In practice, those prices may be prices of an intraday market or the prices incurred by reserves activation as a last resort. The whole expected cost of correction is then obtained by multiplying the expected amounts needed for adjustment times the price.

For this reason, moving the whole trading process could be advantageous for RES-E: the financial consequences of adjusting forecast errors are reduced because the whole period is moved. Besides decreasing the forecast error, the trading period is also adjusted with respect to price-dependent flexibility costs.

Of course, flexibility prices exhibit more complex and stochastic patterns in reality, demand may look different. However, the point being made here is that intermittent RES-E might have impact on optimal timing in markets and is strongly related to things such as prices of flexibility. In conclusion, the forecast error at times of high electricity and balancing prices is to be minimised.

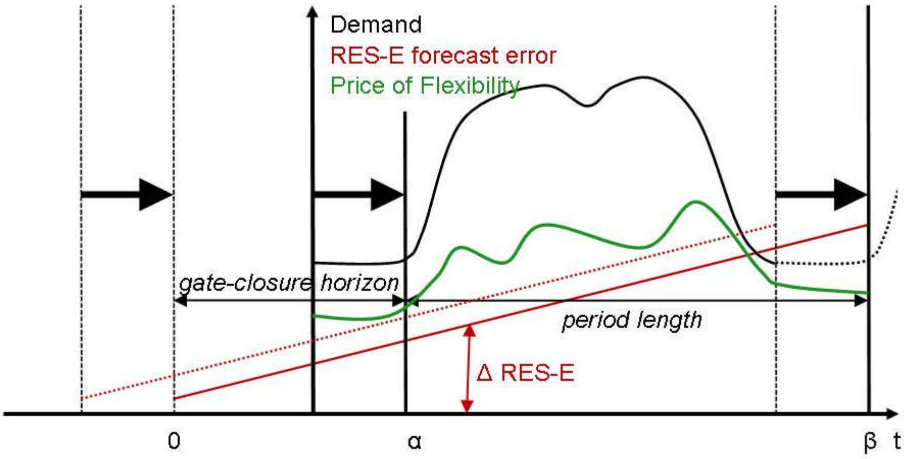


Figure 6: Time determinants in power markets - Moving the period

7.2.2. Challenges

The considerations made above neglect technical constraints of market participants: Start-up costs and minimum up times are the ones known. However, the often emphasized shift to a more flexible production park does not necessarily lead to a situation where all production and consumption (with exception of intermittent RES-E) is easily changed in dispatch by short term price signals and totally free of inter-temporal constraints. It is more likely that the efficient outcome is the optimal trade-off between "total flexibility" and the cost of this flexibility. This does surely not exclude DR measures.

Relating to the possible changes in timing presented above, a system with shortened gate-closure horizon and trading period length, might decrease the risks of RES-E portfolios but increase those of the large base-load plants portfolios: the former has less risk to forecast their real-time output and the latter has more risk to determine their operation early enough to make economic start-up and ramping decision. This could be even seen as a regression towards the current situation as several European power exchanges offer the possibility to bid so-called block orders today. The submission of a block order allows indeed the implicit inclusion of start-up costs. If the gate-closure horizon or the trading period length is shortened significantly, this would deter the setting of the right upstart incentives for base-load units. For this reason, section 7.4 addresses possible market design options to include start-up costs implicitly and to facilitate the inclusion of traditional base-load units.

An approach to optimise gate closure times and related questions, such as the length of the period to be cleared simultaneously, is presented in appendices 9.3 and 9.4.

Besides the operational risks such comprehensive timing changes may impose on unit commitment, the pure organisational transaction costs are likely to be large: Changing shifts of trading staff appears to be costly since personnel expenses are likely to rise. Furthermore, it is also to be expected that the related changes of company-internal processes require a lot of effort.

7.3. Congestion management options embedded in the DA coupling

Grid operation always includes the risk of contingencies which lead to congestions. Thus, those have to be taken into account in the congestion management process. For instance, the choice of the snapshot for DA security analysis includes uncertain assumptions of load, (both intermittent and dispatchable) generation and topological status of the grid. Those assumptions are therefore likely to not hit the reality, though they may be good as assumptions.

Facing such challenges, TSOs usually choose some kind of pessimistic case at DA, resulting into a physical use of the network lower than what would be expected according to an average case, that is to say in lower DA cross-border transfer limits than the maximum possible in an average case. Provided that cross-border transfer limits are updated at intra-day timeframes, this physical margin could be progressively released and given to intra-day markets up to real time.

This process could be made flexible if the pessimist case is made flexible, according to a risk parameter handled by the TSO. If the risk is set at a lower value, there is more cross-border capacity at DA and less to release at Intra-Day. If the risk is set at a higher value, there is less cross-border capacity at DA and more to release at intra-day.

Such an option has several strong prerequisite that are not currently fulfilled in any EU country:

- Risk parameters must be explicitly identified and accounted for in the XB capacity calculation process;
- Recalculation of XB capacity must be done repeatedly at ID.

Moreover, joint cross-border redispatch agreements between neighbouring TSOs, both physical and financial, would significantly increase the acceptable range of risk.

If these prerequisites are fulfilled, the risk parameter chosen by TSOs could transfer cross-border capacity at DA to cross-border capacity at ID, and vice-versa.

7.4. Designing a market to support convergence to (local) equilibria

The arguments given in 7.2 at first sight support a market design in which each single hour is being traded in its optimal time ahead delivery, given there be no sufficient intraday trading possibility. This is not the full truth if market participants do have inter-temporal constraints. In the classic sense, inter-temporal constraints of power plants emerge from start-up costs, minimum up times, etc. However, they may also represent characteristics of future market participants such as short term storages or demand response entities. For the case of start-up costs it can be shown that for a market with independent hourly bid curves, inefficient Nash-equilibria exist. This is also true if a market simply allows for the submission of one bid curve for a couple of hours (cf. Elmaghraby and Oren, 1999).

A market not yielding efficient price signals must be considered problematic for its use as a mechanism supporting efficient integration of RES-E feed in.

This consideration does in turn lead to the finding that complex bids are required in markets to allow market participants with special constraints efficient usage of that market.

Although this might seem uncritical, it makes the whole situation more complex since it establishes a trade-off between the time ahead the delivery when the first allocation is made (cf. 7.2) and the quality of the price signal established by allowing for complex bids covering several succeeding hours.

7.4.1. Necessity of complex bids

In this section, the necessity of complex bids for efficient price signals with units having inter-temporal constraints is described. The explanation is mainly based on Elmaghraby and Oren (2009).

Basically, a certain period in time for the delivery of electricity can be segmented into different markets, e.g. the markets for all hours of one day. Alternatively, they could also be segmented into markets for different supply / demand profiles. This is displayed in Figure 7 and Figure 8. Figure 7 shows a set up where a period with changing demand is sliced into sub periods of equal length, which is generally the case for European Day-Ahead markets. However, this is not an inevitable approach; the given period could also be sliced into different profiles which are then auctioned (Figure 8). Those do not necessarily need to be rectangular, basically a large range of different shapes could be imagined.

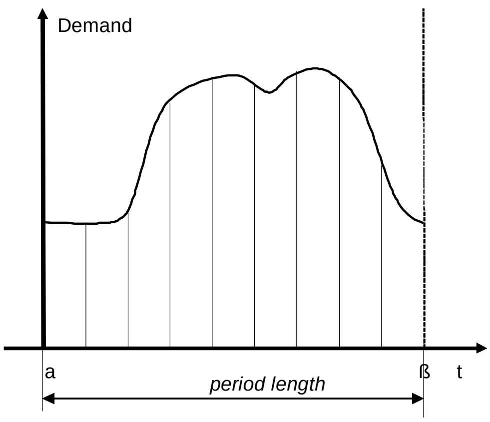


Figure 7: Creating markets by vertically slicing a period of delivery time.

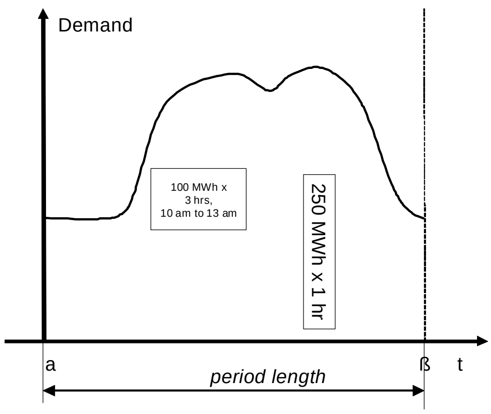


Figure 8: Creating random markets by partitioning the same period into different supply profiles.

Block bids which are common in most European markets represent such flexibility in deciding whether a unit wants to bid into the market for single hours or the one for specific profiles (blocks). The rationale behind the arguing in favour of block bids is the fact that the start-up costs have to be included into the bid. If only hourly bids are allowed, then inefficient equilibria may occur which yield a higher level of total cost satisfying a given demand respectively a lower share of demand supplied at a given cost. Both formulations are equivalent to a loss in overall welfare. If this situation is a Nash-equilibrium at the same time, no single market participant would have an incentive to change his bidding behaviour and so the situation is inefficient but stable.

7.4.2. Implementation of the 'right' complex bids

On the one hand, one might argue that block bids might become less important as 'inflexible' technologies (i.e. high start-up costs) may diminish. However, the development of technology enabling responsive demand, new storage technologies etc. may create a need for complex bids suiting those specific needs. For example, a short term energy storage could well be operated with a stochastically optimised dispatch algorithm at a continuous market, but the availability of specific storage bids formats might increase uncertainty in operation and increase in investment security (cf. Schinz, Weber, Hartkopf 2009).

If complex bids are used to accommodate for time-related inflexibilites of market participants, they do somehow relate to the length of resulting production/load programming. Thus, for example block lengths and lengths of periods to be cleared off simultaneously are technology-dependent which is demonstrated by example in appendix 9.3.

Interesting formations of complex bids can be found at Nordpoolspot, e.g.: There one can submit 'flexible' hourly bids which are characterised by a limit price and a quantity only. The bidder then leaves it to the PX algorithm to calculate the binary decision and the hour. This is a way to model the limitations of storage plants: Flexible in time, but limited in energy.

7.5. Liquidity concepts

Liquidity is often referred to as the ability of trading some usual amounts of some asset in a market without significantly affecting the price. This makes it both convenient to value the asset hold and to trade it at its supposedly fundamental price. Beyond that, liquidity is often related to 'immediacy': The ability of trading the asset instantaneously without having to wait too long that a crossing order arrives (Grossman, Miller, 1988).

There are 3 reasons why a market might be considered 'illiquid':

1. The requested trade quantity exceeds the capabilities of all other market participants.
2. The quantities requested are available but are withhold due to imperfect competition.
3. The requested quantity is available, but not bid into the market right now, but will supposedly be bid into the market later.

The first 2 problems can obviously not be cured by pure market design measures; regulatory intervention might be appropriate in those situations. For the last reason, there is a lack in immediacy. If the market participant experiencing this situation incurs a cost of waiting (e.g. his hedge has to be completed) which is not the valuation of all other market participants, then a so-called market maker can provide liquidity. Such a situation is shown in Figure 9: In t=0, a large demand bid D+ arrives. There is no corresponding supply bid(s), therefore the demand bid cannot be executed in t=0. However, the opposing bid S+ arrives at t=1. Then, the bids can be matched.

This does however imply that the market participant has to wait some time (in our example: one period). If waiting is costly to him, then he would be willing to pay some money to have his bid executed earlier. This is where a 'market maker' comes in (Figure 10): He would then do an inter-temporal arbitrage: He would short sell a quantity sufficiently large to be matched with a share or all quantity of the outstanding order. Then, he would close his position in t=1.

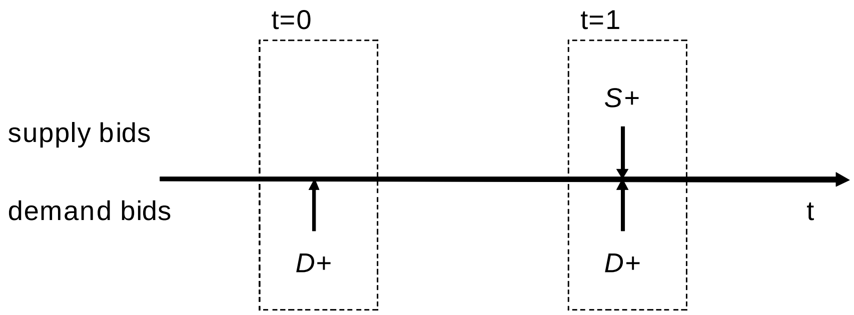


Figure 9: A lack of immediacy inhibits the demand bid to be executed: The required supply bid will (supposedly) arrive later.

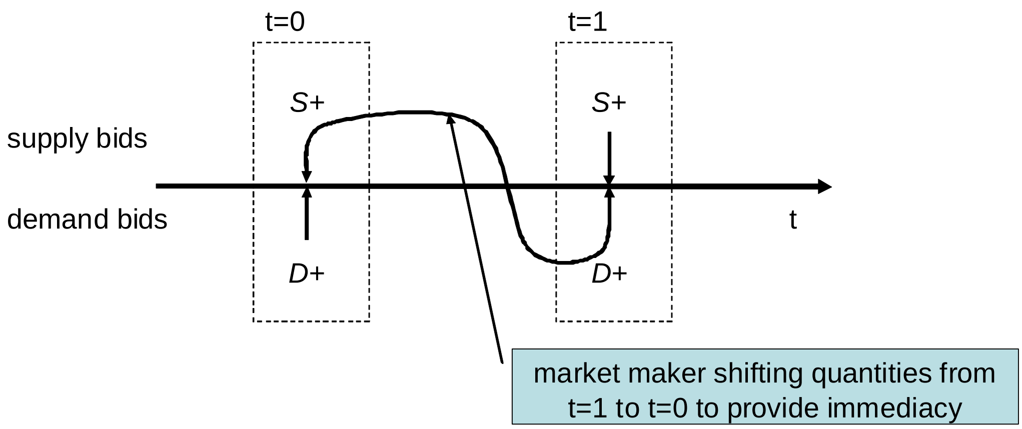


Figure 10: A market maker can provide immediacy by shorting the missing quantity in t=0 and closing his position in t=1.

The market maker concept described above can be applied in markets with sequential discrete auctions or in continuous markets. Grossman and Miller (1988) show that provision of immediacy by market makers has an equilibrium, i.e. there is a relation between demand and supply for immediacy. However, one may not expect that all real markets are always in their equilibrium: An equilibrisation requires price signals, which by nature do not indicate an equilibrium, i.e., one may not expect markets to always be in equilibrium. This could recently be observed in the German Day-Ahead market (Bundesnetzagentur, 2010).

Adversely, if illiquidity (in terms of lacking quantities offered, i.e. reasons 1&2) is perceived to remain, then one could check whether there are fundamental reasons hindering the market from efficiently matching supply and demand. Those may be high barriers to market entry, discouraging arbitrage (both inter-temporal and between markets, such as between OTC and PX). Complementary to the argumentation in favour of optional markets, market participation should be simple and have sufficiently low barriers to allow for high liquidity. Further to that, monetising the potentials of technically complex assets has always required some level of specific know-how, such as stochastic optimisation for the case of storage plants (Bellman-Method, etc.). A sub-optimal level of appropriate unit commitment planning under uncertainty (which is a main characteristic of the electricity industry) might also lead to perceived illiquidity in the sense that quantities are not made available though they could.

On the other hand, necessary financial security requirements are important in order not to jeopardize trust in the market participants.

As a last resort, regulatory measures to mitigate market power problems etc. can be chosen. For the example of the market for procuring balancing services, Batlle et al. (2007) propose a regulatory intervention to limit the price difference between bids for positive and negative control power.

7.6. Degrees of freedom in market prices: caps and floors

As pointed out in section 4.2.2, several markets are subject to heavy regulatory intervention. In this section, we will discuss negative prices and their economic meaning and the exclusiveness of markets.

Negative prices

Some European PXs do allow for negative prices. This seems counter-intuitive at first sight, since electricity is generally considered as a “good”, not a “bad”. Here, we will show why negative prices are useful, can increase welfare and represent a Nash equilibrium.

We consider a 2 period example with an elastic demand as given in Figure 11. There are 2 power plant types:

Plants	Start-up costs / [€/MW]	Variable costs [€/MWh]	Penalty for single period operation [€/MWh]
P1: Baseload @ 500 MW	10	20	30
P2: Peaker @ 250 MW	2	50	0

All plants be perfectly able of part-load operation, have no minimum load and each plant type have an unlimited number of competitors. However we require the competing plants to have ε higher variable costs than the ones given in the table. The reason for this is to ensure a unique solution for the unit commitment problem. The penalty for single period operation can be considered as a proxy related to costs incurred by short up-times, such as higher stress and thus ageing of plant components.

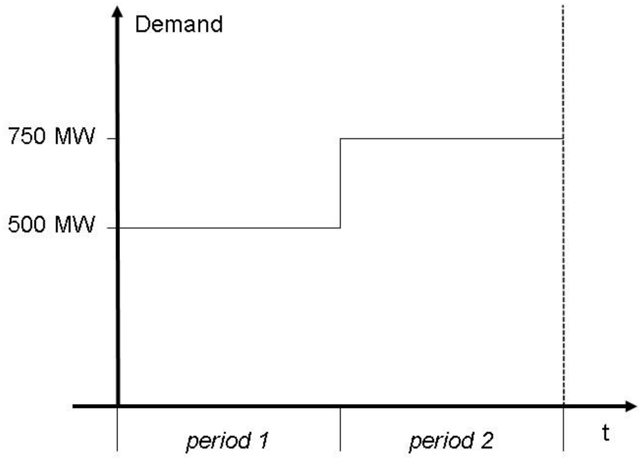


Figure 11: Inelastic demand over 2 periods

Then, the efficient dispatch would be to have plant P1 operating at full output in both periods and plant P2 operating in period 2 only. This assumption leads to the result that none of our 2 plants can make revenues higher than their cost, since they would lose their bid to the competing plants. Therefore, prices and revenues minus hourly variable cost per MW (RMVC – 'revenues minus variable cost') can exactly be calculated.

The sum of RMVC over time for each plant is exactly the amount needed to cover the plants' start-up cost. This is ensured by the competition argument. Furthermore, the solution is an equilibrium, since deviating from their bids would make each plant worse off: Either they would lose their bid to the competing plants or they would make a loss. Therefore, one starts with plant P2 determining the marginal price for the efficient production choice (operate in period 2 only). Therefore, the price in period 2 has to be determined by the marginal costs of P2 to produce exactly in that hour as plant P2 is price setting in this period. Given the efficient dispatch, the RMVC of plant P1 is 32 in period 2. Together with the competition argument it has to be -22 in period 1, to ensure that revenues do not exceed costs. This leads to an equilibrium price of -2 in period 1. The numbers are given in the table below:

Period	Price	RMVC(P2)	RMVC(P1)
1	-2		-22
2	52	2	32

Besides, as discussed above, the outcome is also an efficient dispatch. For the equilibrium to emerge it does not matter whether detailed cost structures are public information since it is a Nash equilibrium.

Therefore, negative prices can both be justified and efficient. It is obvious that too strict caps / floors are able to lower market efficiency. Given the case that negative prices were not allowed in our example, truth-revelation for plant types P1 would be impossible. The maximum welfare loss in the given example would be: |-2| EUR/MWh x 500 MWh = 1,000 EUR.

Mandatory markets: effect in such cases

As shown above for the example of a price floor too high, market design flaws are generally able to decrease market efficiency. If such a market is made mandatory (i.e. no secondary trading is possible), design flaws may not become obvious. Under a flawed market design, traders would supposedly try to escape that market place to a market where efficiency can be achieved. Thus, decreasing trade activity and liquidity on this market could indicate a market design problem. If such an escape is not possible (e.g. no secondary trading possibility exists), this signal would remain hidden and inefficiency would be likely to prevail. (cf. Ockenfels et al., 2008).

7.7. RES-E support schemes

The basic RES-E support mechanisms (explicitly referred to in EC 2009/28) are a Feed-in tariff system, a market premium system and a quota system with tradable green certificates. As discussed in chapter 3, those RES-E support regimes do have different influences on plant dispatch and investment in plants (cf. Held, 2007). Although long-term questions are not a subject of OPTIMATE, questions of dispatch indeed are and they are expected to have significant impact on integration costs. In the following paragraphs, the different regimes will be discussed with respect to their impact on market integration and price signals they produce.

Feed-in Tariff System

A specific actor is responsible for buying the whole amount of qualified renewable energy injected into the grid. In return, entitled producers obtain a fixed tariff for their renewable energy. Typically, the feed-in tariff is coupled with priority access and priority dispatch: the system operator shall give priority to qualified RES installations insofar as network operation permits to do so (cf. Directive 2009/28/EC).

Main characteristics:

- A fixed feed-in tariff is paid, with tariff levels being differentiated according to the type of renewable energy source.
- Inherently to the fixed tariff, there is no influence of the volatility of market prices on RES production.
- In order to provide investment certainty, the feed-in tariff is guaranteed for a specified duration (e.g., 20 years) after the date of commissioning of a plant.
- Frequently, a tariff degression is introduced: the level of support is successively lowered for new RES installations connected to the grid in subsequent years.

Priority dispatch seems reasonable if considering the usually very low variable production cost of intermittent RES-E (i.e. close to zero). However, as shown in section 7.4, negative prices may well be justified in market equilibrium. Priority dispatch therefore has to be defined carefully: Does it mean a feed-in “whatever it may cost”? Or is the cheaper solution of curtailing intermittent RES-E feed-in at negative prices and compensating the producers accordingly more appropriate?

In addition, a fixed feed-in tariff depletes the incentive of non-intermittent RES-E plants, such as biomass, since their technological flexibility is not aligned with market price signals. Therefore, feed-in tariffs might lead to distorted incentives which lead to distorted prices.

Market Premium

In the case of market premiums, the eligible producer directly sells (through a balancing responsible) his renewable energy to the market. On top of the wholesale market price, the producer receives an additional fixed bonus, defined per MWh sold. In contrast to the feed-in tariff, under a market premium there is no purchase guarantee for renewable energy. Therefore, this scheme may be supplemented by an additional premium for eligible renewable producers for balancing costs, since he bears the production forecast risk. However, it is likely that overall risk could be reduced by pooling the forecast of (geographically non-identical) intermittent producers. So, overall imbalance costs could be reduced which would improve efficient market integration. Therefore, it seems advisable to allow for such arrangements.

Main characteristics:

- The producers get paid the market price and are thus exposed to fluctuations resulting from market forces.
- In parallel, eligible RES producers receive a bonus as a fixed component of their revenue on top of the market price. This bonus may be differentiated according to technologies.
- It is possible to implement caps/floors that the sum of the market price plus the premium may not exceed/fall below.

The latter part of the characteristics named above partly relates to the question of negative prices and the question whether society is willing to pay for losses the RES-E producer incurs by selling power at negative prices. Without a cap/floor, the intermittent RES-E producer would sell down to a price as low as the negative value of the premium.

Green Quotas with Tradable Green Certificates

In a quota set-up, the producer sells directly (through a portfolio responsible) its energy to the wholesale market. Additionally to the market price, the producer obtains a green certificate for each unit of renewable energy (typically one MWh). These green certificates constitute a financial product and can afterwards be traded on a specific market, the green certificate market. Demand for green certificates is created by the authorities through imposing a green quota on electricity consumers (downstream green certificate system) or producers (upstream green certificate system). In order to comply with the quota, consumers/producers may consume/produce the corresponding amount of green electricity themselves or, alternatively, purchase green certificates on the certificate market. Green producers can hence sell their certificates and get money. E.g., in an upstream green certificate system, conventional producers buy certificates to meet the renewable energy quota. In a downstream green certificate system, retail companies typically fulfil the percentage requirement by purchasing green electricity and/or green certificates on behalf of their customers.

Main characteristics:

- RES producers get paid the market price, like any other producer.
- In parallel, they obtain a green certificate per unit of renewable energy produced.
- Typically, one green certificate is issued per MWh of green electricity produced. Technology differentiation may be introduced by allocating different weights to the "units of green electricity" produced (e.g., for less mature technologies 0.9 MWh of green production for one certificate, whereas more mature technologies may first obtain a green certificate for 1.3 MWh of production).
- Financial liquidity of the green certificate market is a major prerequisite for the functioning of this support scheme. The evolution of the volume of required quotas is also of importance as the green certificate market may be volatile if there is no clear public information about the future amount of quotas set by the authorities.

Given a certain price per Green Certificate, this scheme can be considered as providing similar incentives to the RES-E producer: Both regimes would let the decision on whether to market the electricity to the producer, yet adding a fixed amount for every MWh sold. Therefore, the Green Certificate-scheme could be proxied by the market premium-scheme within the OPTIMATE simulations.

8. Results and Conclusion

8.1. Day-ahead markets

DA markets usually describe a set of hourly double-sided auctions executed simultaneously at one day ahead of delivery. As design options, not only the characteristics of single markets were identified, but also different approaches to couple markets to allow for implicit auctioning of XB capacity. In discussions concerning the effects of such a market integration – especially concerning the integration of RES-E – it is often said that this increased liquidity be beneficial. It would thus be interesting to try to quantify the different outcomes that different levels of market coupling yield.

Besides that, it has been shown that a sufficient array of complex bids is likely to support efficient market outcomes. This relation is maybe not very straightforward – which makes it an interesting candidate for OPTIMATE simulations. Related to that, it has also been shown that too tight floors / caps on market prices hinder truth-revelation and welfare-maximisation.

Concerning the dispatch behaviour of RES-E units subject to a FIT on the one hand and a premium-related scheme on the other, overall welfare / emission comparisons could bring valuable input to the debate concerning how much a society should be willing to pay to keep RES-E up in case of negative prices.

To match the technology available with the steadily changing forecast values of RES-E production, not only a sufficient set of complex bids seems helpful, but also an optimised timing of gate closure and periods to be auctioned simultaneously. However, although this point does in theory relate both to DA and ID markets, it will in practice be more relevant for ID considerations. The reason for that is that changing timing at DA would probably lead to large transaction and adjustment costs. For the simulation on DA it would nevertheless be interesting to measure the effects in numbers which such measures (moving both GCTs and length of the periods to be auctioned simultaneously) could have.

Some general conclusions concerning the reactivity and liquidity were made which represent more the implicit model assumptions of OPTIMATE, but which are worth being considered when interpreting the model outcomes. These are the claims for optional markets with low barriers to entry thus encouraging participation and allowing for reasonable monitoring of the market behaviour.

8.2. Intraday markets

Though sometimes implemented as a series of discrete double-sided auctions, ID markets are very likely to evolve as continuous trading systems. They will therefore be modelled as such in OPTIMATE. They do have a perceivably important role in intermittent RES-E market integration since they are the platforms for matching the continuously improving RES-E production forecast and the technological capabilities of the remaining production (and consumption) park, as noted above. For this coordination function to maximise utility, it is important that the technically available capabilities such as XB capacities, production adjustment are made available to the market. For the case of XB capacity, the ID recalculation of capacities taking into account improved information and the current grid situation could help optimising the use of available technical infrastructure. Furthermore options for XB rent allocations could be investigated with respect to overall system costs / emissions.

An often stated claim concerns the time before delivery until when ID adjustment is possible. The argument is made that shortening this period would help RES-E producers to economically adjust their feed-in balance. Quantifying this argument with the help of OPTIMATE could contribute to the discussion.

As for the DA markets, the question on a sufficient level of complex bids and their impact on efficiency should be considered for ID simulations as well.

The general considerations named for the DA market are also valid for the ID market: to interpret model-outcomes for a specific scenario, one has to take into account efficiency-lowering factors, such as e.g. limited entry, harsh regulation and non-optionality.

8.3. Balancing mechanisms

“Balancing mechanisms” is an umbrella term for a number of balancing regulations and regulating power sub-markets, e.g. primary reserves, secondary reserves and tertiary reserves. These have different time horizons and bidding conditions. A common feature of all markets is that conventional generators, traders and consumers are responsible for keeping their day-ahead and intraday plans. Otherwise, they risk having to pay for balancing power. RES-E generators are not responsible for their schedule under all support schemes. The widely applied feed-in tariff levies this obligation to other participants, such as the TSO, reducing transaction costs for the single RES-E operators. Distinguishing these two options with regard to allocative effects could yield interesting results.

One-price and two-price systems for balancing deviations were discussed. Penalties on one-way deviations can have an effect on market actors’ optimisation and bids, and implicitly on overall system efficiency. The possible benefits of a comparison of both options are therefore an issue to be addressed in the further scientific and industry-wide discussion.

Another aspect addressed in this report is the choice between pay-as-bid and marginal pricing for the procurement of regulating power. The TSO can opt for either of these to procure enough capacity and energy for regulation. However, pay-as-bid schemes lead to gaming incentives that can lead to similar outcomes as marginal pricing. Regarding the overall system without a strong focus on the exercise of market power and single actor's informational advantages, a limitation on marginal pricing seems justified.

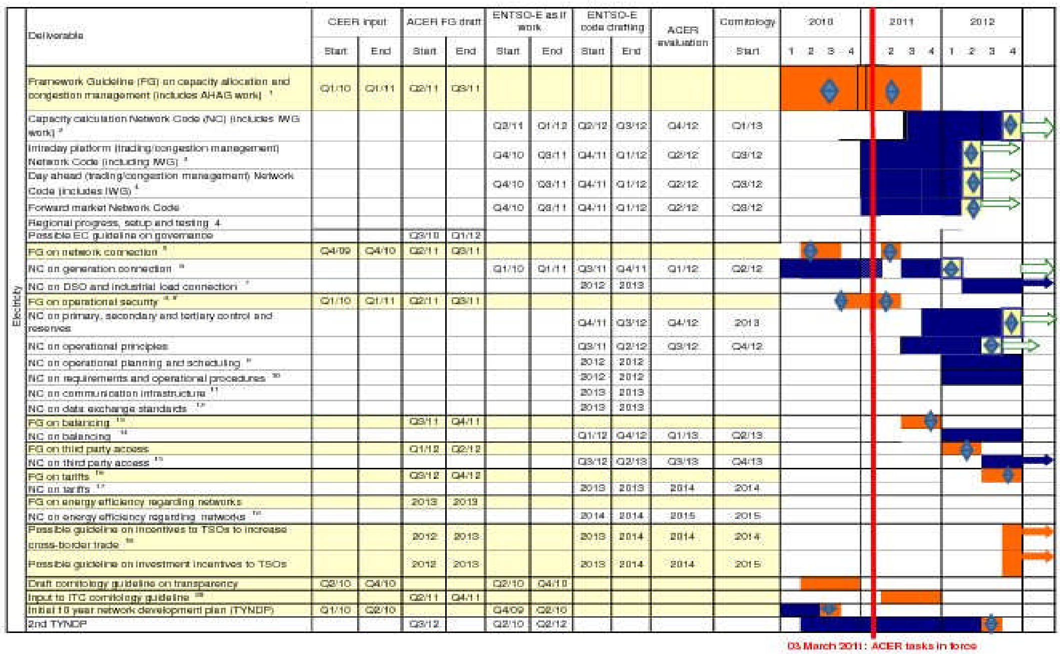
Possible cross-border exchange of balancing and regulating power reserves is a relevant option for a Europe-wide optimisation approach. Nowadays, in the Nordic countries, there is a common market if the congestion on international interconnectors resulting from DAM and IDM allows it. Otherwise, local bidders are activated. This is one option that could be extended to the whole of Europe, following the increasing integration of DAM and IDM. However, several different approaches exist, such as the German Grid Control Cooperation (GCC) and the France-UK "Balancing Inter-TSO" (BALIT). In addition, reserving a certain share of interconnector capacity for balancing, namely from internationally fluctuating RES-E, seems an option that might be taken into account in future considerations.

![optimate logo] ![Seventh Framework Programme logo]

9. Appendix

9.1. The 3a-Plan

The 3a-Plan was created by the EC, both ENTSOs, and the ERGEG. It presents a work plan for the creation of the framework guidelines and related network codes stipulated by legislation of the 3rd package.



Deliverable	CEER input Start	CEER input End	ACER FG draft Start	ACER FG draft End	ENTSO-E as if work Start	ENTSO-E as if work End	ENTSO-E code drafting Start	ENTSO-E code drafting End	ACER evaluation	Comitology Start
Framework Guideline (FG) on capacity allocation and congestion management (includes AHAG work) [1]	Q1/10	Q1/11	Q2/11	Q3/11						
Capacity calculation Network Code (NC) (includes IWG work) [2]					Q2/11	Q1/12	Q2/12	Q3/12	Q4/12	Q1/13
Intraday platform (trading/congestion management) Network Code (including IWG) [3]					Q4/10	Q3/11	Q4/11	Q1/12	Q2/12	Q3/12
Day ahead (trading/congestion management) Network Code (includes IWG) [4]					Q4/10	Q3/11	Q4/11	Q1/12	Q2/12	Q3/12
Forward market Network Code					Q4/10	Q3/11	Q4/11	Q1/12	Q2/12	Q3/12
Regional progress, setup and testing 4										
Possible EC guideline on governance			Q3/10	Q1/12						
FG on network connection [5]	Q4/09	Q4/10	Q2/11	Q3/11						
NC on generation connection [6]					Q1/10	Q1/11	Q3/11	Q4/11	Q1/12	Q2/12
NC on DSO and industrial load connection [7]							2012	2013		
FG on operational security [4, 8]	Q1/10	Q1/11	Q2/11	Q3/11						
NC on primary, secondary and tertiary control and reserves							Q4/11	Q3/12	Q4/12	2013
NC on operational principles							Q3/11	Q2/12	Q3/12	Q4/12
NC on operational planning and scheduling [9]							2012	2012		
NC on requirements and operational procedures [10]							2012	2012		
NC on communication infrastructure [11]							2013	2013		
NC on data exchange standards [12]							2013	2013		
FG on balancing [13]			Q3/11	Q4/11						
NC on balancing [14]							Q1/12	Q4/12	Q1/13	Q2/13
FG on third party access			Q1/12	Q2/12						
NC on third party access [15]							Q3/12	Q2/13	Q3/13	Q4/13
FG on tariffs [16]			Q3/12	Q4/12						
NC on tariffs [17]							2013	2013	2014	2014
FG on energy efficiency regarding networks			2013	2013						
NC on energy efficiency regarding networks [18]							2014	2014	2015	2015
Possible guideline on incentives to TSOs to increase cross-border trade [19]			2012	2013			2013	2014	2014	2014
Possible guideline on investment incentives to TSOs			2012	2013			2013	2014	2014	2015
Draft comitology guideline on transparency	Q2/10	Q4/10			Q2/10	Q4/10				
Input to ITC comitology guideline [20]			Q2/11	Q4/11						
Initial 10 year network development plan (TYNDP)	Q1/10	Q2/10			Q4/09	Q2/10				
2nd TYNDP			Q3/12		Q2/10	Q2/12				

3-year plan EC - ERGEG/ACER - ENTSO-E - ENTSOG for items where they interface

The High Level Group (HLG) consisting of top-level representatives of EC, ERGEG, ENTSO-E and ENTSOG, established with the aim to coordinate the interim phase of 3rd IEM Package implementation, had its first meeting on 26 January. One of the important decisions was to develop a common full 3-year timetable for all 3rd Package work in cooperation between ERGEG, EC and the ENTSOs (i.e. framework guideline and network code developments and consultations. A possible future development of the planwould also include all other work where EC, ACER and the ENTSOs interface with each other and with stakeholders). The major goal of such a tool is to achieve a common understanding of the sequencing of actions of different bodies and to plan the resources necessary to successfully reach the goals. The current draft builds on several meetings between EC, ERGEG, ENTSOG and ENTSO-E. An April HLG meeting is to discuss the resulting single common draft 3-year plan; the Bodies and Directors of the involved organisations need to check and approve in May, and stakeholders are to be informed in Florence on 10-11 June 2010. The plan is indicative and represents the best view at the time of drafting but act

LEGEND

FG Framework Guideline
NC Network Code
Common scoping discussions
ENTSO- E work
Regulator work (ERGEG/ACER)
ACER evaluation of NC
Comitology process (including EC input to Comitology)
Likely public consultations

COMMENTS

1 AHAG and IWGs = vehicles for scoping phases; currently AHAG/IWGs also include work for regional progress, setup and testing; the continuation of this work past the official beginning of FG work may be best treated in a later stage of this planning work but are displayed here until the later work is completed
2 Scoping through Q1/11 then start formal code work after completion of official FG, i.e. in Q4/11, then 12 months
3 12 months informal NC then shortened 6 months formal NC
4 12 months informal NC then shortened 6 months formal NC
5 Unofficial work of ERGEG, then shortened 3 months by ACER
6 Parallel FG/NC work is a (well reasoned) exception
7 The development has not been planned yet
8 Includes operational procedures in an emergency, security and reliability rules, interoperability
8 Unofficial work of ERGEG, then shortened 3 months by ACER
9 The precise development schedule has not been planned yet
10 The precise development schedule has not been planned yet
11 The precise development schedule has not been planned yet
12 The precise development schedule has not been planned yet
13 Including also data exchange and settlement
14 Needed clarity on the scope of the FWGL, NC and goals
15 Needed clarity on the scope of the FWGL, NC and goals
16 It needs to be assessed whether further harmonisation is needed
17 Needed clarity on the scope of the FWGL, NC and goals
18 Needed clarity on the scope of the FWGL, NC and goals
19 Need to be determined by ACER in light of FG on tariffs
20 LRAIC work by ACER starting in Q2/11

Source: 18th Florence Forum 10, 11 June 2010

9.2. Electricity Pools and Electricity Exchanges

Two generic electricity market design schemes (cf. e.g. Stoft 2002) are often considered: pools and exchanges. These two are not fully independent, but rely on how tight the system is on transmission capacity and how this scarcity is signalled to the market.

9.2.1. Electricity Pools

Pool qualifies an area where a central market place does exist, establishing a DA reference solution through a clearing mechanism. This central market place includes mandatory unit bidding, except for small or special participants whose inputs have to be forecasted (including for instance distributed renewables). Based on the aggregate production (supply) function and the rather inelastic consumption (demand) function, the energy dispatch is centrally managed through locational price signals. An electricity pool hence combines the auction mechanism with a central management of the unit-commitment problem.

OTC trade is allowed only under the condition that it discloses its programme (source, sink and volumes) before DA market closing time.

Pools make sense only under the assumption that TSO and Market Operator cooperate strongly during the clearing, by some kind of integrated or iterative process: the Market Operator forwards a draft clearing to the TSO where all the system is somehow included, then TSO constrains in and out the relevant generation, then the Market Operator finalizes its clearing. The overall result after clearing is then theoretically closer to the System optimum (considering DA parameters). In some pools, multi-part bids or side payments[12] are applied in order for electricity generators to cover other than pure hourly marginal costs.

9.2.2. Power Exchanges market

A power exchange qualifies an area where a central market place does exist, establishing a DA reference price through a clearing. This price is determined by considering bids and offers, without constraining on and off any equipments, such as generators, according to System Operation security rules: the only constraints considered are those explicitly included by participants, through block bids or any other multi-temporal authorized bids[13].

The clearing of the exchange may either be continuously or discrete (auctions).

[12] Stoft (2002) even distinguishes pools and exchanges by whether they have side payments. However, pools are also often understood as synonym for centralised dispatch systems or – at least – unit bidding systems.

[13] Constraints necessary to guarantee a clearing value in any numerical case may also be considered, but they are non significant in our analysis

9.3. Length of the period to be cleared

As already stated, most Day-Ahead markets in the liberalised electricity industry cover all 24 hours of the following day, often allowing for block bids which are sometimes standardised and may sometimes be configured by each bidder. The cause of this is in history for two reasons: (1) the day ahead planning of unit commitment is a practice which existed long before liberalisation (cf. Weber 2009) and (2) the 'traditional', inflexible electricity demand exhibits a strong periodicity on a daily basis which implies that block bids are most importantly required to cover a period of up to 24 hours.

In systems with heavy intermittent production, this may change: When making the simplification of 'residual demand', i.e. demand minus intermittent feed-in, the periodicity may change. This could easily make a difference for economic efficiency if not adjusting the period length of the Day-Ahead auction accordingly: In the presence of costly flexibility and improving intermittent RES-E production forecasts in time, the optimal time for allocation of hours de-linked from another block may well be different from the current practice.

This is illustrated by Figure 12 and Figure 13: The DFT (discrete fourier transform) shows, that the strong daily periodicity of hourly national consumption data diminishes if massive intermittent wind feed-in is subtracted. The factor of 15 for the wind impact was chosen arbitrarily, the emphasis is on demonstrating that massive intermittent impact on electricity markets may change the "classical" behaviour.

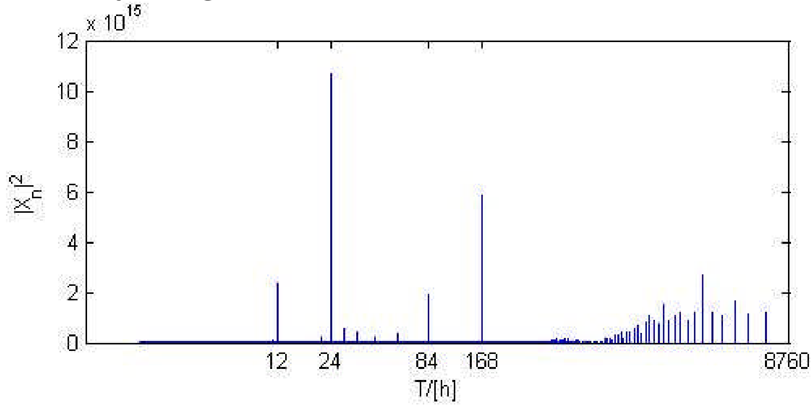


Figure 12: DFT spectral analysis of 2007-2009 UCTE load data for Germany.

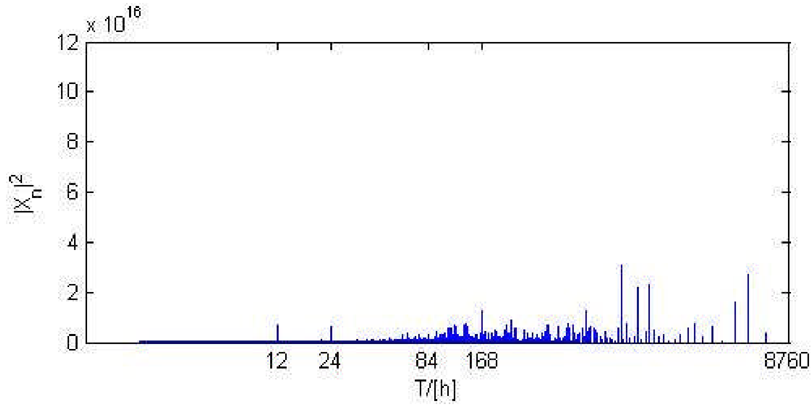


Figure 13: DFT spectral analysis of 2007-2009 UCTE residual load data for Germany, calculated with 15 times the actual wind feed in of that time.

This consideration is however not conclusive, since intermittent feed-in from wind is (besides PV) not the only source of changes in demand patterns – demand response may be as well.

9.4. Optimising timing in energy markets

Given the assumption that clearing of electricity markets subject to stochastic infeed would take place at discrete points in time before delivery, then it does presumably matter when those clearings take place. This is on one hand due to the fact that flexibility in production changes is costly with costs increasing the closer the change occurs to delivery. On the other hand, forecasts of stochastic production are necessarily the better the closer they are made before delivery (otherwise, if they were worse, one would simply not do that).

This leads to an optimisation problem: While the forecast error is supposed to be monotonically decreasing the closer the delivery period is, the flexibility costs are increasing. Therefore it is possible that a minimum of overall costs exists which is related to a market clearing time. For our whole analysis, we assume that the stochastic feed-in will always be marketed which is equal to both the non-existence of negative prices or a “feed-in-whatever-it-may-cost”-regime. Figure 14 and Figure 15 show how described behaviour may look like. The formulation of the optimisation problem was inspired by Wang et al. (2010).

Figure 14: The predictability of stochastic wind in-feed is the better, the closer the hour to predict is in time. The forecast error is often measured by the RMSE.

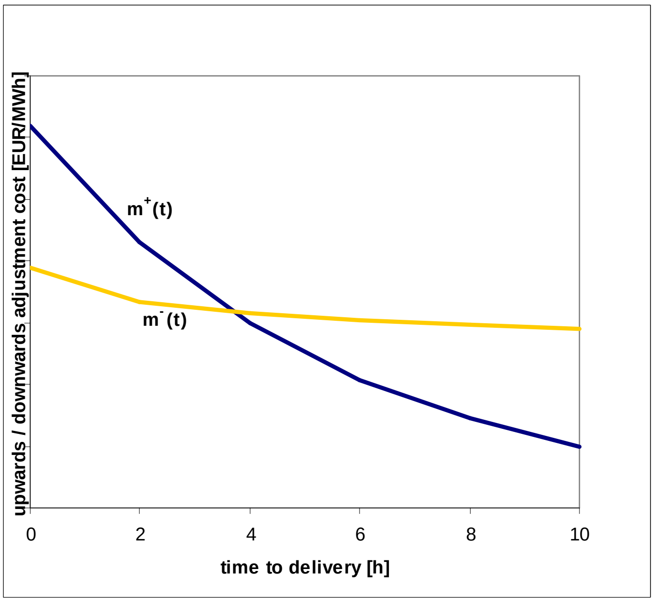


Figure 15: Flexibility is costly: If this was not the case, there would be no point in marketing stochastic feed-in some time in advance. Vice versa: Flexibility has value since not all market participants can provide short-term elasticity. The shape of the graphs is an example and only meant to be illustrative.

Converging forecasts

The RMSE (root mean squared error) is used to measure the quality of the forecast and is defined as

$$RMSE = \sqrt{\frac{1}{N} \cdot \sum_{i \in N} (x - \hat{x}_i)^2}$$

where N is the number of observations, x be the true value and $\hat{x}_i$, $i \in N$, the predictions of x. If the forecast error is normally distributed, then RMSE is the unbiased estimator of the standard deviation. Although we will not require the forecast error to be normally distributed, we will call RMSE "variance parameter" and write it as

$$\sigma(t)$$

Where t is the time ahead delivery with $t \geq 0$ and $\sigma(0) = 0$, $\dot{\sigma} > 0$. The forecast error r be distributed to a probability density function (pdf)

$$pdf_{\text{forecast}}(r, \sigma(t), t)$$

For generality, the pdf may change over time.

Valuing flexibility

For the price of flexibility, we assume that it is a fixed transaction fee which is to pay both when buying and selling volumes (else there would be no prices specifically signalling scarcity of flexibility). However, we neglect price elasticity to volumes but allow for different flexibility prices for upwards and downwards regulation. The price for flexibility is written as

$$m^+(t) \text{ resp. } m^-(t)$$

Depending on whether upwards or downwards regulation of the flexible units is required.

Solving the problem of optimal market clearing time(s)

For the simple case of one market clearing for one hour t_{GCT} hours ahead delivery and real-time imbalance settlement the objective function of the social cost minimisation problem is:

$$
\begin{aligned}
K = \quad & m^{-}(t_{GCT}) \\
& + m^{+}(0) \cdot \int_{0}^{\infty} pdf_{forecast}(r, \sigma(t), t)\, dr \\
& + m^{-}(0) \cdot \int_{-\infty}^{0} pdf_{forecast}(r, \sigma(t), t)\, dr
\end{aligned}
$$

The first term of the sum is the cost of flexibility required by the initial market clearing at t_{GCT}. The flexibility required is necessarily downwards regulation since energy production from a stochastic supply source is supposed to be positive. From this point of view, a very early GCT seems favourable. The downside of this benefit is represented by the two operands following: They represent the expected cost of adjustment which is more costly, the higher the prediction error is. Following our assumptions, the prediction error is the higher, the earlier the market clearing takes place.

For the case of N hours cleared at once, the objective function is the sum of the objective functions for the particular hours:

$$K_{multi} = \sum_{n \in N} K(t_{GCT} + n)$$

To model set-ups with multiple market clearings between the initial clearing and delivery, the respective objective function can be formed in an equal manner, though with modified pdfs, calculated for each time step accordingly. Though the analytical solution of the problems given may be impossible, simulations might give that.

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