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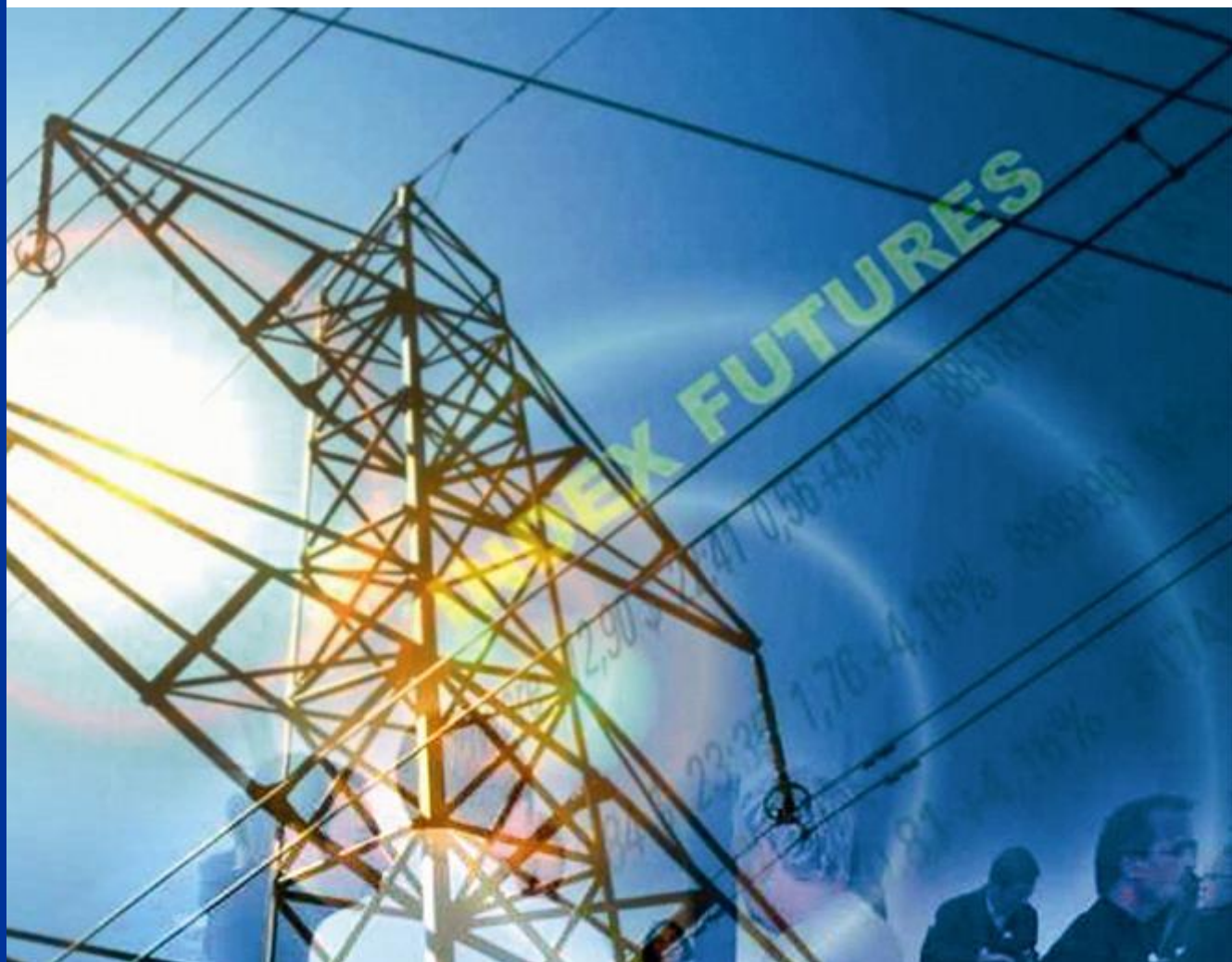
OPTIONS FOR GREEK COMPLIANCE WITH TARGET MODEL

A report to RAE

October 2012



OPTIONS FOR GREEK COMPLIANCE WITH TARGET MODEL

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Pöyry is a global consulting and engineering company dedicated to balanced sustainability and responsible business. With quality and integrity at our core, we deliver best-in-class management consulting, total solutions, and design and supervision. Our in-depth expertise extends to the fields of energy, industry, transportation, water, environment and real estate. Pöyry has about 7,000 experts and a local office network in about 50 countries. Pöyry's net sales in 2011 were EUR 796 million and the company's shares are quoted on NASDAQ OMX Helsinki (Pöyry PLC: POY1V).

Pöyry Management Consulting provides leading-edge consulting and advisory services covering the whole value chain in energy, forest and other process industries. Our energy practice is the leading provider of strategic, commercial, regulatory and policy advice to Europe's energy markets. Our energy team of 200 specialists, located across 14 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

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EXECUTIVE SUMMARY

The Greek Regulatory Authority for Energy, RAE, has commissioned Pöyry Management Consulting ('Pöyry') to produce this report on the transition of the Greek electricity market to the European Target Model ('Target Model') for electricity. This report reflects the material Pöyry prepared for a related workshop commissioned by ADMIE, the Greek TSO, but is also informed by the discussions during that workshop and subsequent analysis by the project team.

The development of a single European electricity market by 2014 is a major theme of the Third Package[1] of European energy legislation, which came into force in March 2011. The rules for market integration are based around the European Target Model for electricity, which is strongly influenced by the markets of North West Europe. This raises significant challenges for the Greek market whose design is fundamentally different from the approach used in North West Europe. The scope and aim of our study is to provide a high level assessment of the various options that may be viable for Greece in order to provide a background document for a regulatory consultation.

The different options described in this report are designed to be compliant (subject to detailed legal interpretation) with the requirements of the Framework Guidelines and their corresponding Network Codes, all of which are under development. This report considers the (draft) Framework Guidelines and Network Codes that were publicly available during the production of the draft version of this report. Therefore, it does not reflect:

- either the version of the Electricity Balancing Framework Guidelines submitted by ACER to the EC in September 2012; or
- the version of the CACM Network Code submitted by ENTSO-E to ACER in September 2012.

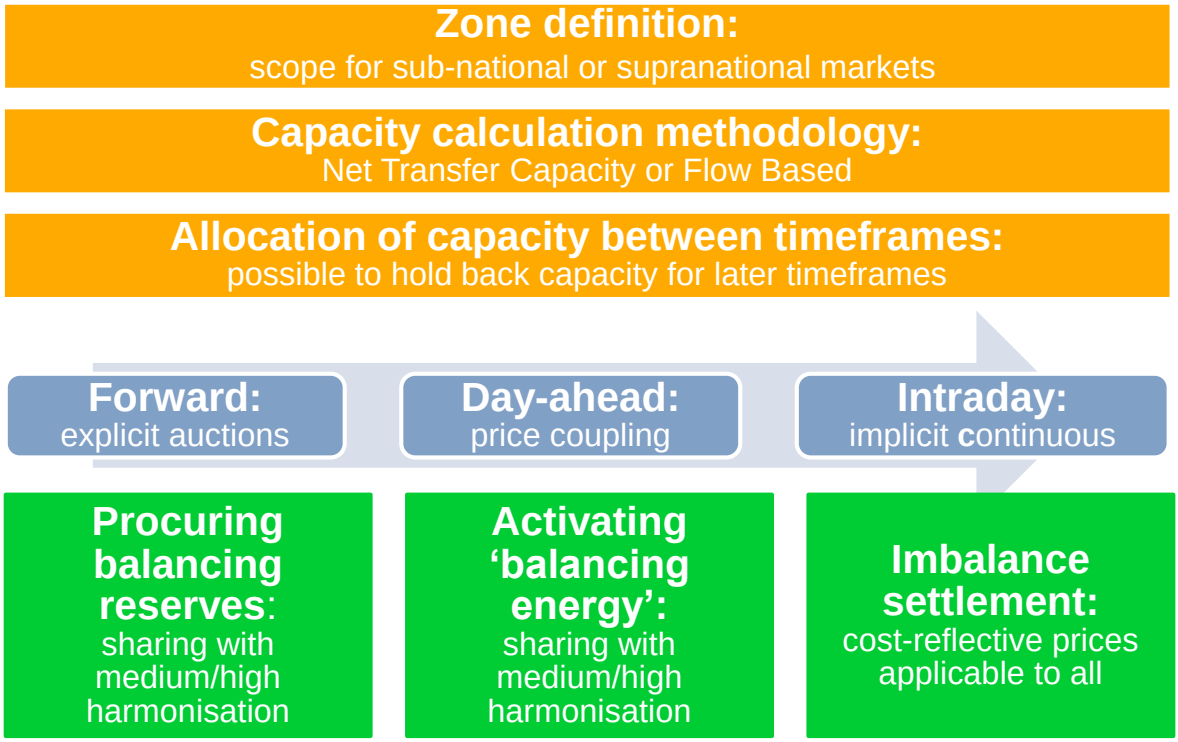
However, full and detailed legal review of the final Network Codes (when they become available) will be needed to establish a more definitive view on compliance.

Target Model

The detailed rules for the Target Model will be defined through Framework Guidelines (FGs) and associated European Network Codes (NCs), in particular in relation to (interconnector) capacity allocation and congestion management (CACM), and balancing. The Target Model does not require a specific market design for all European electricity markets; rather it specifies rules for the transfer of electricity between them. Figure 1 provides a high-level summary of the Target Model for electricity in terms of nine building blocks.

[1] Published in the Official Journal of the European Communities on 14 August 2009, the provisions of the Third Package came into force on 2 March 2011.

Figure 1 – Building block summary of Target Model



Overview of current Greek electricity market design

The initial market design of the Greek market was aiming at developing healthy competition between the incumbent (PPC) and new market entrants, whilst ensuring appropriate levels of security of supply, system adequacy and reliability.

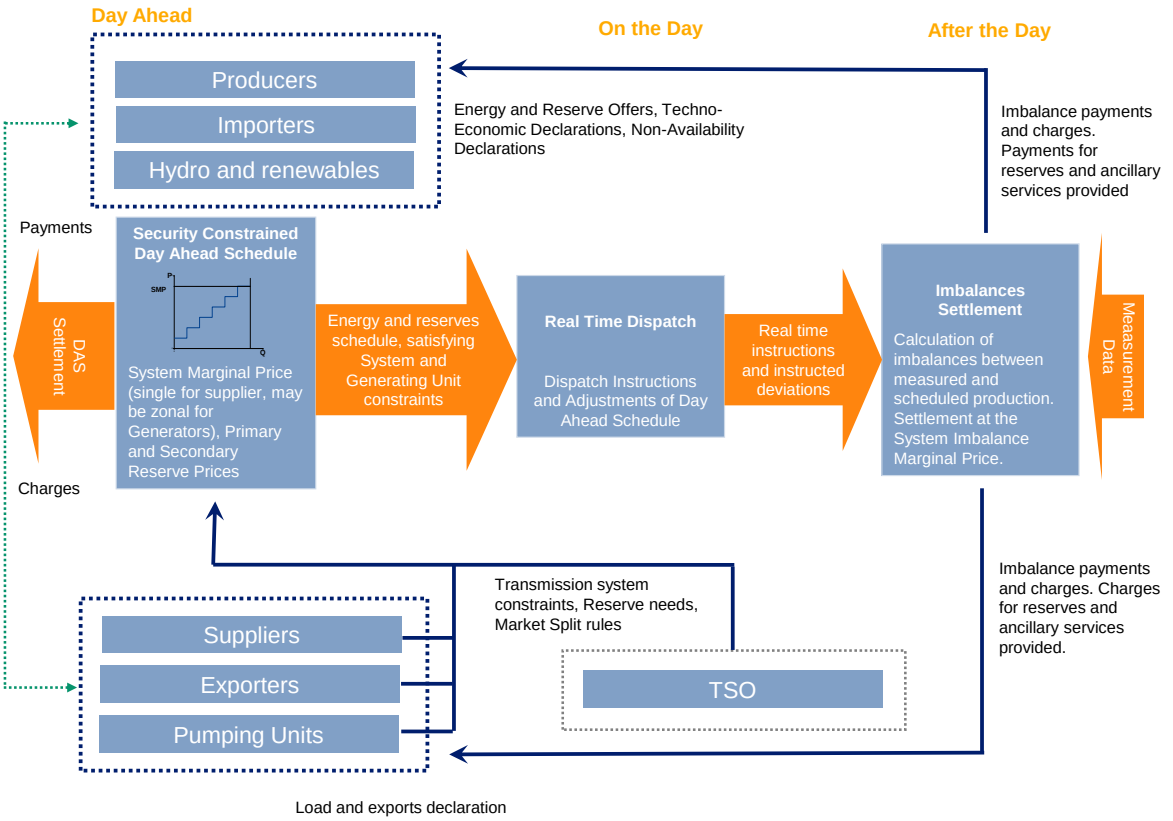
The main features of the current Greek design include:

- a gross mandatory pool (the Pool) which uses a ('technical') algorithm to determine the prices and schedule for the entire energy market, to help encourage new entry by providing a guaranteed route to market and robust reference price;
- co-optimisation of energy and reserves to help maintain security of supply;
- multiple generation inputs into the Pool algorithm, including economic bids, cost data (including shut down costs) and technical characteristics of the generator units;
- central dispatch of generation;
- prices which are produced by ex-post run of Pool algorithm for use in settlement of instructed and uninstructed imbalances;
- separate Capacity Adequacy Mechanism (CAM) intended to incentivise plant availability and new build; and
- Cost Recovery Mechanism, intended to ensure that all units generating upon receiving a dispatch instruction cover at least their costs (plus an additional margin).

Figure 2 summarises the current Greek market, with the Day Ahead Schedule (DAS) at its heart. The DAS minimises the overall cost of meeting demand for the next day whilst

ensuring adequate reserves through a co-optimisation process. It also takes into account constraints on generation unit commitment and the need for reliable system operation.

Figure 2 – Overview of the Greek market



Analysis of gaps between Target Model and current Greek design

Table 1 uses our building block approach to summarise the main gaps that we have identified between the current Greek market design and the Target Model. These gaps are broadly consistent with the incompatibilities highlighted by RAE in its December 2011 roadmap[2].

The table highlights that the substantive gaps are as follows:

- the introduction of a Day Ahead Market (DAM) to implement price coupling in line with the Target Model (the current Greek market does not offer price coupling);
- the introduction of an Intraday Market (IDM) and supporting trading platform (when no opportunities for intraday rebidding exist in Greece at present);
- the requirement for balancing actions to face a marginal price (at present, activation of downwards balancing energy in Greece is subject to a cost-based payment);

2 Basic Principles in the Redesign of the Greek Wholesale Electricity Market. Roadmap and Action Plan by RAE in the context of the implementation of the EU Target Model', RAE, December 2011.

- the need for a shortening of the settlement imbalance period to a maximum of 30 minutes under the Target Model (currently 1 hour in Greece); and
- the requirement for cost-reflective pricing for imbalances under the Target Model (at present, the Greek market has zero pricing for (upwards) uninstructed imbalances (long position)).

As the balancing rules for the Target Model are still under development, there remains uncertainty on the degree of harmonisation of products and procurement processes that will be required (as well as the extent of facilitation required for demand-side provision of reserve). Therefore, the extent of any gap between the Target Model and the current Greek arrangements for balancing and imbalance are not yet clear. However, we note that in principle, any material harmonisation of balancing arrangements will prove difficult to accommodate the co-optimisation of reserve and energy in the Greek market if that is not done in other markets.

For the first three building blocks (related to the availability of interconnector capacity), the gaps are primarily in terms of processes and timing rather than more substantive issues.

Table 1 – Gap analysis between Target Model and current Greek market design

Building block	Current Greek design	Target Model	Gap
Zoning	Sub-national generation prices possible but never implemented	Regular review of zone definition	Aligned in principle but need to comply with formal review process; Question mark about single demand price with zonal generation prices
(Interconnector) capacity calculation	NTC (although Flow Based has also been analysed by the Greek TSO)	NTC allowed but Flow Based preferred for 'meshed networks'	Uncertain as Flow Based not yet implemented in practice (and 'peninsula' status?)
Allocation of (interconnector) capacity between timeframes	Forward – annual, monthly (and daily) auctions No capacity held back for day-ahead or intraday	Approval role for NRAs, with scope to reserve capacity for balancing	Some capacity may need to be held back until at least the day-ahead timeframe
Forward	Explicit allocation of Physical Transmission Rights	Explicit allocation of physical or financial transmission rights using common platform	Move to common platform for transmission rights; allow forward energy trading, possibly cross-border only?
Day-ahead	Mandatory gross pool with 'technical' algorithm to determine SMP; co-optimisation of energy and reserve	Price coupling based on firm day-ahead prices and volumes;	Day-ahead bids, algorithm and timings not consistent with Target Model
Intraday	No Intraday trading (or opportunities for rebidding)	Continuous implicit trading with congestion pricing	No Intraday trading (or opportunities for rebidding for dispatch)
Procurement of balancing reserves	Co-optimisation of energy and reserve (primary, secondary and tertiary)	Harmonised products and procurement processes to facilitate sharing of reserves between TSOs	Participation of demand-side; Product definition and procurement through Pool?
Activation of balancing energy	Uses bids and costs for Pool; marginal (ex-post) price for increased production; cost-based (re)payment for reduced production	Harmonised products with marginal pricing and selection based on Merit Order	Participation of demand-side; Product definition and activation based on Pool inputs? Marginal pricing not used for reduced production
('Uninstructed') imbalance settlement	Generators receive zero price for upwards imbalance; pay marginal (ex-post) price for downwards imbalance; Hourly settlement period	Incentives for all parties to self-balance (day-ahead&real time); cost-reflective prices for all; Settlement period no more than 30 minutes	Zero price for upwards imbalance; Length of settlement period

The Cost Recovery Mechanism and Capacity Adequacy Mechanism are not topics specifically addressed in the CACM NC, and hence are not included in Table 1. However, we note that because they could potentially distort bids into the market coupling (by offering additional revenue streams)[3], they could be argued to be inconsistent with the spirit of the Target Model. In addition, the Cost Recovery Mechanism allows for prices and costs to be submitted separately and used for different purposes, which could distort bidding incentives. As RAE is already reviewing the future design of these mechanisms, separately to its consultation on Target Model compliance, options for their future design are not part of the scope of our report.

In addition, we have carried out a brief analysis of the gaps between the Target Model requirements and existing electricity market design in Italy and in the SEE countries on the northern borders of Greece (Albania, FYROM, Bulgaria). In summary, Italy is the market that is the closest to the Target Model, with substantial gaps for the other countries. Market redesign projects are under way in those countries, albeit at different stages of development.

Compliance options

We have investigated three different high-level options for Greece to comply with the requirements of the Target Model. Those are:

- adaptation of the current Greek model ('Adaptation option');
- the North Western European Power Exchange Model ('NWE option'); and
- a mixture of forward bilateral with a pool used for the DAM ('Hybrid option').

In general, the forward timescale is one of the key areas of differentiation between our options, as it has significant impacts on the relative importance of the DAM and IDM. Under the Target Model, forward trading provides an opportunity for nomination of physical interconnector flows against physical transmission rights. Such nomination is not possible from the time of the DAM onwards, as price coupling determines the residual flows from that point onwards[4].

As the balancing rules are still under development, there remains uncertainty on the degree of harmonisation of products and procurement processes that will be required. In addition, it is unclear how strong the requirement will be to facilitate the use of demand-side resources for balancing. Therefore, we differentiate our options in relation to the strength of harmonisation of procurement and activation of balancing resources.

This has knock-on implications for the settlement of imbalance arrangements (itself a key area of differentiation), in particular whether or not the Pool is used to produce (uninstructed) imbalance prices.

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3 This situation is not unique to Greece. We note that a number of other countries expected to be at the heart of the implementation of the Target Model either have or are considering the development of some form of capacity payment mechanism (including existing capacity payment regimes in Ireland and Spain, Government proposals in GB, France, Belgium, and discussions in Germany and Italy). Other markets have strategic reserve mechanisms (e.g. Sweden, Finland), and in many markets the TSO's contracts for reserve and other ancillary services have the potential to influence prices in the spot markets.

4 Subject to the provisions for transitional arrangements for explicit intraday interconnector access set out in Articles 91 to 95 of the July 2012 draft of the CACM NC.

In presenting the options considered in this report, we have considered only six of the building blocks to be relevant. We have not considered variations in the remaining three building blocks (all related to how much interconnector capacity is available for allocation):

- zone definition;
- capacity calculation; and
- allocation of capacity between timeframes.

This is because in these areas, the CACM FG and draft CACM NC generally set out requirements for processes to be in place (e.g. around regulatory review and approval) rather than particular market design features. Therefore, compliance with the Target Model requires these processes to be implemented rather than necessarily a change to market design. These processes will in turn require a further set of decisions to be taken (e.g. periodic assessment of market zoning), which is beyond the scope of our current project (particularly given the need for supporting detailed quantitative analysis).

Table 2 summarises the three options that we have developed for the Greek market to comply with the requirements of the Electricity Target Model. The text in bold highlights the key differences between the options. In the table we distinguish between the Intraday market (IDM), the day-ahead market used for price coupling (DAM) and the Pool which is a continuation of the existing Greek arrangements.

Table 2 – Summary of options for compliance with Target Model

Building block	Adaptation option	NWE option	Hybrid option
Zone definition	To be assessed every two years with scope for review	To be assessed every two years with scope for review	To be assessed every two years with scope for review
Capacity calculation methodology	Flow Based (unless meet criteria for retaining NTC)	Flow Based (unless meet criteria for retaining NTC)	Flow Based (unless meet criteria for retaining NTC)
Allocation of capacity between timeframes	NRA approval	NRA approval	NRA approval
Forward	Common European platform for (re)trading of long-term interconnector rights; Physical interconnector rights **(Physical) forward energy trading through existing Greek Pool (run earlier on D-1, before DAM)**	Common European platform for (re)trading of long-term interconnector rights; Physical interconnector rights **Physical (and financial) bilateral trading of energy**	Common European platform for (re)trading of long-term interconnector rights; Physical interconnector rights **Physical (and financial) bilateral trading of energy**
Day-ahead	**(Limited) adjustment volumes** in price coupling through DAM **(power exchange)**	Price coupling through DAM **(power exchange)**	Price coupling through DAM **(through which all previously uncontracted volumes must be traded)**
Intraday	(Limited) adjustment volumes in price coupling through IDM (continuous trading)	(Limited) adjustment volumes in price coupling through IDM (continuous trading)	(Limited) adjustment volumes in price coupling through IDM (continuous trading)
Procuring balancing reserves	**Co-optimisation in Pool**	**Separate ancillary service market(s)**	**Separate ancillary service market(s)**
Activating balancing energy	Marginal pricing **with activation based on Pool**	Marginal pricing; **Separate balancing mechanism**	Marginal pricing; **Separate balancing mechanism**
Imbalance settlement	30 minute settlement period; Cost-reflective pricing **based on ex-post Pool** (and accounting for market coupling results)	30 minute settlement period; Cost-reflective pricing **based on actual balancing costs**	30 minute settlement period; Cost-reflective pricing **based on actual balancing costs**

Adaptation option

This option is intended to achieve compliance (subject to detailed legal interpretation) whilst carrying out minimum change. This is intended to ensure that market participants would not have to completely change the way they participate in the market when

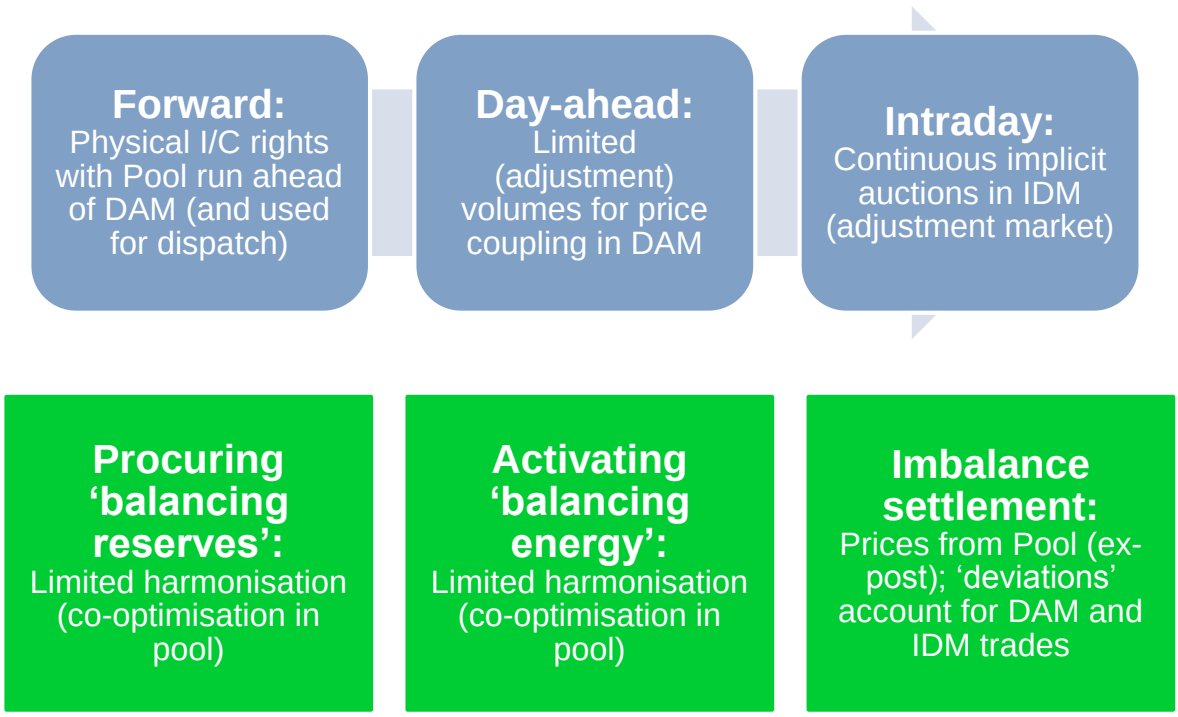
compared to the current situation, and the TSO and Market Operator would broadly have the same responsibilities as now.

We assume that many of the existing features of the Greek market would remain intact (although moved slightly forward in time), with compliance being achieved by the gross mandatory pool becoming a 'forward' rather than a Day Ahead market. This could allow the market to maintain the form of a gross mandatory pool with central dispatch.

Figure 3 details the structure of the 'Adaptation' option under the six relevant building blocks. The key features of this option (beyond the introduction of Day Ahead and Intraday coupling) are:

- **current DAS to be run earlier on D-1 so that it acts as a new 'forward' market ahead of the DAM** (which effectively operates as an adjustment market); and
- **revision of the calculation of imbalance volumes to take account of the results of the price coupling markets (DAM and IDM),** which therefore imposes extra data management costs on market participants**.**

Figure 3 – Building block summary of the Adaptation option



Both the Capacity Adequacy Mechanism (CAM) and the Cost Recovery Mechanism **could** remain in place within the context of the Pool. The Target Model does not explicitly rule out the use of additional mechanisms, such as the Cost Recovery Mechanism and the Capacity Adequacy Mechanism. However, we note that the impact of this on bids and offers in the Greek market may potentially distort pricing and trade.

NWE option

The description of this option and our recommendations for the extent of change required are based on the markets of Western Europe, which were the basis for the development

of the European Target model. These markets are also the foundation of the Price Coupling of Regions project.

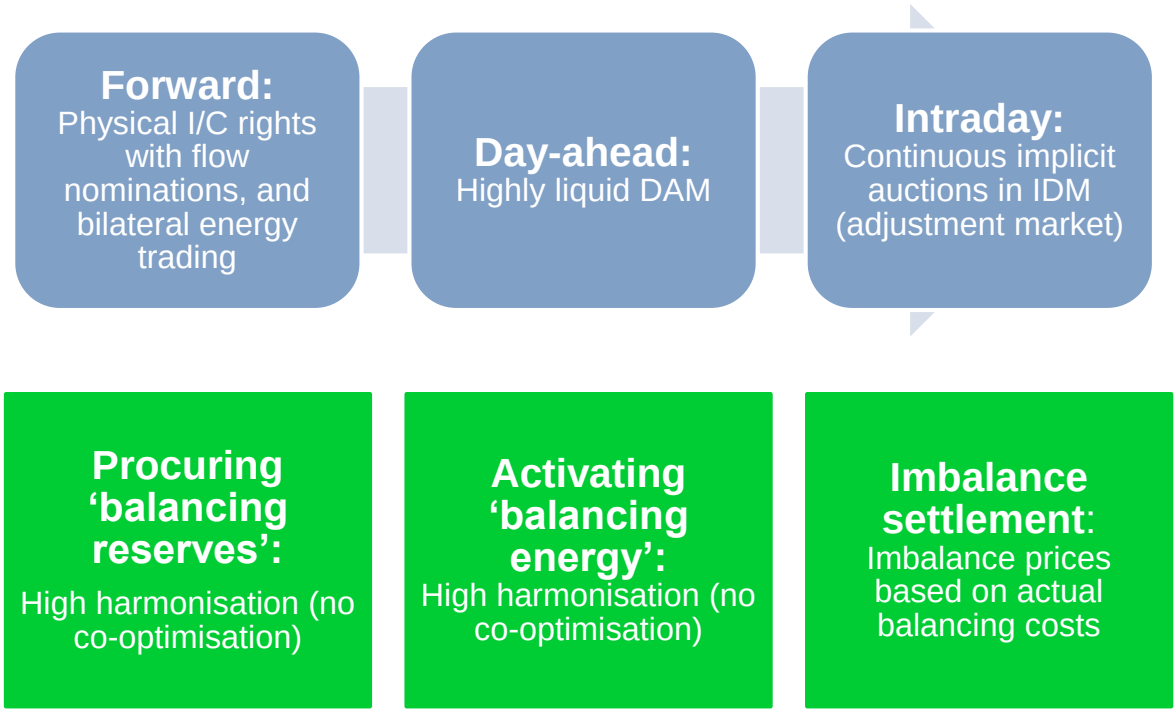
Therefore, the main issue for this option is about the suitability of its design for Greece (given the extent of the change from the current market arrangements) rather than compliance with the Target Model.

Under this option we contemplate a complete market reform with the removal of key features of the current Greek market, such as:

- gross mandatory pool;
- current bid formats (including technical data);
- central dispatch;
- co-optimisation of energy and reserve; and
- optimised imbalance prices (i.e. based on perfect hindsight rather than actual balancing actions).

Figure 4 presents an overview of the NWE option structure under our six building blocks.

Figure 4 – Building block summary of the NWE option



We also assume the removal of the Cost Recovery Mechanism; and (implicitly) the Capacity Adequacy Mechanism. However, we note that a number of the markets in Western Europe either have or are considering the introduction of capacity mechanisms. Although national capacity mechanisms are argued not be within the spirit of the Target Model, many European markets already have or are developing capacity payment regimes and we consider this to be independent of the Target Model discussions.

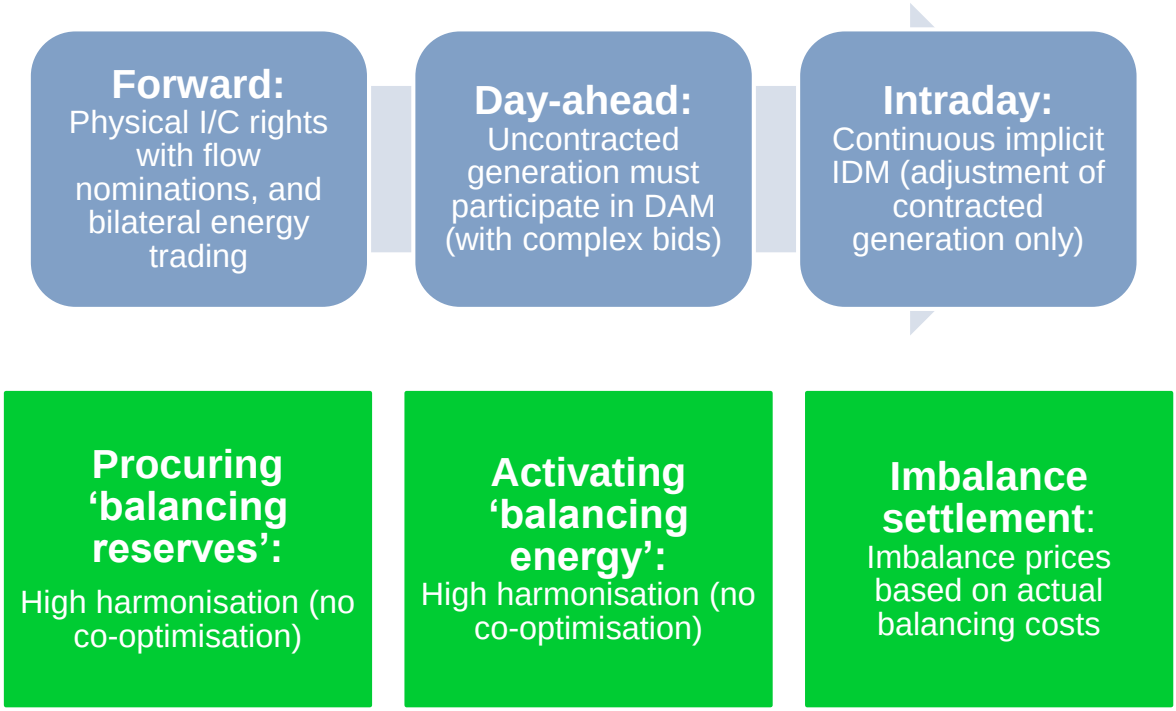
Hybrid option

In our third option, the Hybrid option, we consider the issues around introducing price coupling through a 'voluntary' pool for the DAM as used in Spain and Italy, which are also involved in the PCR project. The pool is voluntary to the extent that physical bilateral contracts can be struck in the forward timescale. However, any available generation without a bilateral contract must then participate in the Day-Ahead market.

This option also requires the removal of the **gross mandatory** Pool (with co-optimisation) that is currently in place in Greece. The pool used for the DAM in our Hybrid option employs only the most technical/complex bids accommodated by the proposed PCR algorithm.

The structure of the Hybrid option under the six relevant building blocks is presented in Figure 5.

Figure 5 – Building block summary of the Hybrid option



Transition

We consider three aspects that would be helpful to RAE in preparing a detailed roadmap for transition:

- summary of the changes required to the current Greek arrangements to implement each of the three options;
- listing of possible intermediate transition steps in moving beyond the minimum change described in the Adaptation option; and
- options for introducing the central systems required to implement the coupled markets at day-ahead and intraday stage.

Table 3 summarises the minimum changes needed across all three options in order to implement the Target Model.

Table 3 – Changes needed under each option

Building block	Common
Zone definition	Introduction of procedures for (regional) zone definition process
Capacity calculation methodology	Testing of Flow Based methodology
Allocation of capacity between timeframes	Introduction of process for regulatory approval of capacity allocation between timeframes
Forward	Introduction of common European platform for (re)trading of long-term interconnector rights: Removal of daily explicit auction for interconnector rights
Day-ahead (DAM)	Introduction of a DAM for price coupling with timings/market processes in line with Target Model requirements (e.g. trading day starting at 0100 Greek time)
Intraday (IDM)	Introduction of IDM with (at least) continuous trading and supporting trading platform, with timings/market processes in line with Target Model requirements
Procuring balancing reserves	Some harmonisation of processes (and potentially products) with neighbouring countries
Activating balancing energy	Some harmonisation of processes with neighbouring countries; Move to marginal pricing for procurement of downwards balancing energy (currently cost-based price)
Imbalance settlement	Settlement period to be reduced to 30 minutes; Cost-reflective pricing for upwards uninstructed imbalances (currently zero)

Table 4 summarises the additional changes required under each option, beyond the minimum changes described in Table 16.

Table 4 – Additional changes needed under each option

Building block	Adaptation option	NWE option	Hybrid option
Forward	Current DAS to be run earlier on D-1	Forward bilateral trading options (physical and financial)	Forward bilateral trading options (physical and financial)
Day-ahead (DAM)	None (all new)	None (all new)	Introduction of new bidding conditions and formats
Intraday (IDM)	None (all new)	None (all new)	None (all new)
Procuring balancing reserves	None (co-optimisation in the Pool)	Ancillary services market(s)	Ancillary services market(s)
Activating balancing energy	Move to marginal pricing for both upwards and downwards balancing energy	Separate balancing mechanism	Separate balancing mechanism
Imbalance settlement	Revised calculation of imbalance volumes to take account of results from coupling markets	Systems for calculating actual costs in energy balancing (as opposed to network actions)	Systems for calculating actual costs in energy balancing (as opposed to network actions)

Possible intermediate steps in transition

Rather than as discrete alternatives, the three options above could be seen as possible different states of the Greek market as it evolves over time, particularly with scope to move from the Adaptation option to either the NWE option or the hybrid option. Therefore, we have identified a number of possible transition steps for moving beyond the basic Adaptation Option:

- make the Forward Pool on D-1 voluntary rather than mandatory;
- remove co-optimisation from the Forward Pool (alongside the development of new reserve markets);
- designate a central agency with responsibility for converting bids from the current Greek format into bids accepted by the market coupling algorithm; and
- allowing rebidding to the IDM to be considered in dispatch.

The steps are not necessarily designed to be followed in the order set out above.

Assessment criteria and next steps

We have carried out a high-level assessment of the possible advantages and disadvantages of each option against the principles that RAE has set out for its review of the Greek market design:

- creation of a stable and predictable market model, which will incorporate sufficient incentives to attract investment;

- environment that will facilitate healthy competition amongst the market participants, which will ultimately be beneficial to the end user;
- maintain the system's security and reliability (especially given the expected growth of RES penetration);
- market model compatible with the EPC (i.e. general model for European Price Coupling), but most importantly compatible with the model of Regional Market of the South-Central Europe (CSE); and
- minimisation of the adaptation cost and time to the Target Model.

Table 5 summarises this high level assessment with the key pros and cons identified highlighted in bold.

Table 5 – High level assessment of advantages and disadvantages

Criteria		Adaptation option	NWE option	Hybrid option
Stable and predictable market model	Positives (+)	▪ Ability to anticipate (possible) further changes to Target Model (e.g. co-optimisation, capacity mechanisms)	▪ (Nominally) a clear legally compliant endpoint; ▪ Provides allies for common resistance to further change	▪ (Nominally) a clear legally compliant endpoint; ▪ Provides allies for common resistance to further change
	Negatives (-)	▪ Storing up more frequent and/or bigger changes for future, particularly if question marks over legal compliance	▪ Further changes required if Target Model continues to evolve	▪ Further changes required if Target Model continues to evolve
Competition	Positives (+)	▪ Gross mandatory pool is route to market for new entrants; ▪ Market power mitigation measures built into market arrangements; ▪ Transparency of reference price from pool	▪ **Arrangements well-understood by foreign players**; ▪ Robustness of DAM results for reference price	▪ **Retention of a (voluntary) pool should help to focus liquidity (providing route to market)**; ▪ May allow gradual removal of market power mitigation measures
	Negatives (-)	▪ Low liquidity (if any) in DAM and IDM may limit 'import' of competitive pressures; ▪ Limited international understanding of specific Greek arrangements	▪ **May need additional (targeted) market power mitigation measures**; ▪ Uncertainty about accessibility of market for new entrants	▪ If Pool arrangements are complex, it may reduce accessibility for foreign players
Security and reliability	Positives (+)	▪ TSOs retain large amount of control	▪ **Interconnection flows may be more efficient (and responsive intraday)**	▪ DAM collects together information on all contracted positions at the day-ahead stage
	Negatives (-)	▪ **Uncertain how schedule and dispatch will interact in practice**	▪ Need new balancing tools (no co-optimisation); ▪ Reliance on intraday adjustments in market	▪ Need new balancing tools (no co-optimisation)
Compatible with CSE (and EPC)	Positives (+)	▪ None (risk of non-compliance)	▪ **Compatible with spirit and letter of EPC**	▪ **Similar to Spanish arrangements, and bid format should be accommodated by the PCR algorithm**
	Negatives (-)	▪ **Use of coupling as adjustment markets not in spirit of CSE and EPC;** ▪ **Possibility of not being fully compliant with detailed rules**	▪ Closer to NWE than CSE	▪ None (fully compatible with CSE)
Minimise adaption time and cost	Positives (+)	▪ **Least change from current arrangements**	▪ Scope to use systems already established in other markets	▪ Range of bids available in DAM may help market players become more comfortable with new arrangements
	Negatives (-)	▪ **TSO needs to update dispatch and 'imbalance settlement' arrangements to take coupling results into accounts**; ▪ Market participants need to have separate systems in place for Greek pool and for coupling	▪ **Major change to current arrangements for all market participants**	▪ **Still need for potentially significant adaption of market features with impact on systems for all market participants**

Summary assessment of the Adaptation option – compliance is questionable

Although this option represents minimum change, which should reduce the time and cost of implementation, it raises a number of major implementation and compliance changes that could be useful to consider in more detail (including expert legal review) as part of the RAE market design project. These include:

- **Whether or not treating the DAM as an adjustment market would be deemed to be compliant with the spirit of the Target Model.**
- **Interaction between central dispatch** (as determined by the bids into the gross mandatory pool) **and the trading in the DAM and IDM** which will be key in understanding implications for the TSO (in balancing the system) and market participants.

Summary assessment of the NWE option – major change for Greece

This option represents a major change from the current arrangements, which is likely to require significant investment in time and costs for changing central systems and market participants' systems. By removing many of the key features of the current Greek arrangements (in particular the gross mandatory pool), there is a need for the development of new balancing tools to help the TSO deliver secure supplies. The option also raises questions (particularly in the initial stages of implementation) about the need for new (targeted) market power mitigation measures.

On the other hand, this option is strongly in line with European requirements meaning that long-term compliance with the Target Model should not be an issue (even if the speed of transition is challenging). It should improve external competitive pressures on the Greek market, either through more efficient interconnector flows or through moving to arrangements that are well-understood by foreign players.

Summary assessment of the hybrid option – softer transition path with higher cost

The Hybrid option similarly represents major change from the current arrangements, with the abolition of the gross mandatory pool in its current form. New ancillary services and balancing markets will need to be introduced (as in the NWE option).

However, the use of a (voluntary) pool for the DAM (even it is in a different form to the current Greek pool) may help to ease the transition to the new arrangements. Greek market players may feel more comfortable about their risk exposure under complex bid formats and conditions (rather than the block bids of the power exchange). The prohibition on withholding physical capacity from the DAM may also help address some of the issues around market power mitigation measures (although may reduce liquidity in the intraday market).

This option should also be compliant with the developments in the CSE region (particularly Spain), as well as the Target Model more generally. Dependent on the governance arrangements, there is a risk though that using a pool with locally-determined rules for the DAM may allow greater scope for direct political interference in market scheduling (than would be possible under a NWE power exchange). One example of this from Spain is the insertion of the subsidised coal plants into the schedule after the daily price has been fixed.

Possible next steps

Our assessment has also highlighted a number of areas in which further evidence may be useful to RAE in deciding which options to develop in more detail. This would enable a more detailed assessment of the different compliance options than is possible within the scope of the current study.

These areas include:

- studies of the main causes of the difference between dispatch and the traded markets, particularly at the day ahead stage to ascertain the importance of co-optimisation, the bid structures used within the gross mandatory pool and re-bidding opportunities in Intraday trading;
- the advantages and disadvantages of more (or less) centralised control over dispatch and the challenges which intraday trading will bring to system operation ;
- circumstances under which regional market integration would provide effective competition for the Greek incumbent;
- indirect costs and benefits of different market models, as well as tangible costs such as system changes;
- further investigation into the detailed legal requirements for compliance (particularly as the Network Codes move closer to finalisation); and
- more detailed review of the proposed developments in neighbouring countries.

1. INTRODUCTION

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However, full and detailed legal review of the final Network Codes (when they become available) will be needed to establish a more definitive view on compliance.

1.1 Approach

The scope and aim of our study is to provide a high level assessment of the various options that may be viable for Greece in order to provide a background document for a regulatory consultation. Therefore, our report is at an appropriate level of detail to assist in the consideration of different possible pathways for compliance.

The options would need to be developed in more detail as the regulatory project moves forward into a detailed design stage, and then ultimately implementation. Indeed, the issues to be discussed in this report would lend themselves to a large and very detailed piece of work before the implementation of any chosen option.

1.1.1 Building blocks

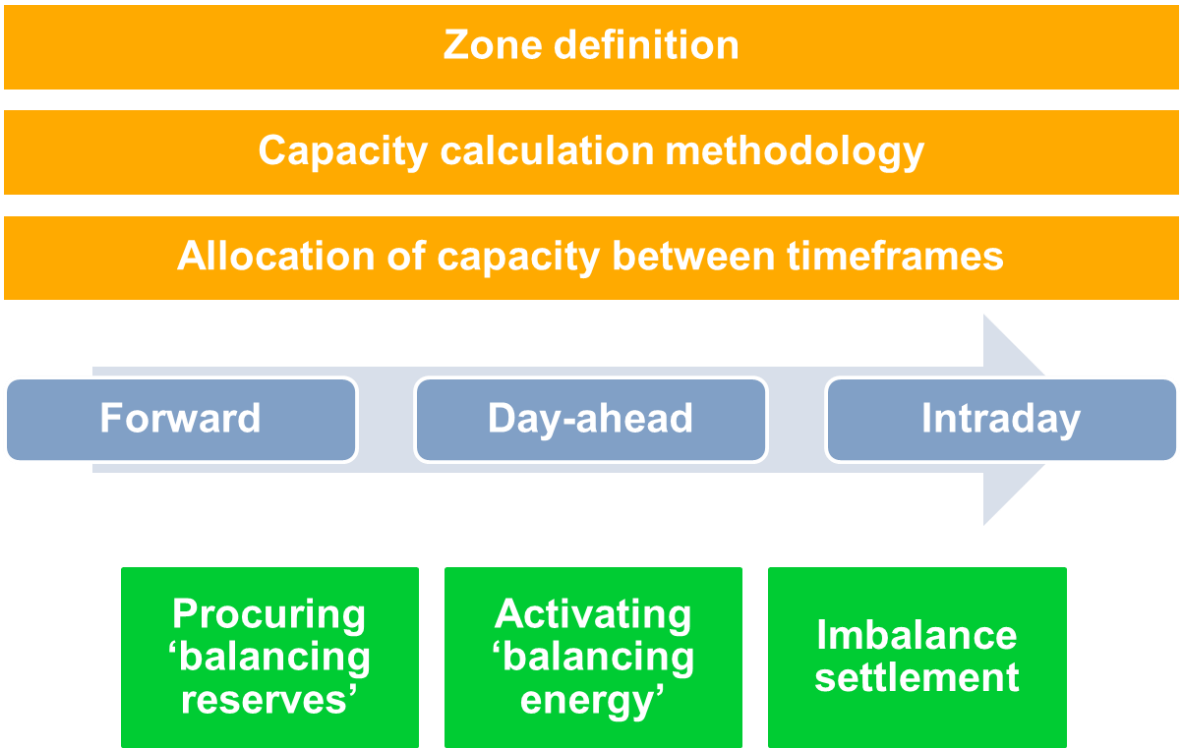
In this report we use a consistent set of nine building blocks to describe the:

- Target Model;
- current Greek electricity market design;
- analysis of gaps between current market design and the Target Model (for Greece, Italy and countries on the northern borders of Greece); and
- possible options for Greece to comply with the Target Model.

Figure 6 summarises our nine building blocks, which reflect the main issues discussed in the CACM FG (which is focused on the allocation of interconnector capacity) and EB FG[5]. This approach provides a common structure for our analysis of current and possible future market designs that helps to frame the discussion of possible options for compliance.

[5] Section 1.3 defines the terms 'Interconnector' and 'Imbalance settlement' as used for the purposes of this report.

Figure 6 – Summary of building blocks



The building blocks in each row can be grouped together under a single question as follows:

- Top three rows (orange) – how much interconnector capacity is available for allocation?
- Middle row (blue) – what are the rules for allocating interconnector capacity in a particular timeframe?
- Bottom row (green) – what are the arrangements for balancing the system?

1.2 Structure of this report

The report is structured as follows:

- Chapter 2 describes the Target Model, at a high-level and in terms of the detailed requirements set out in the CACM FG, Balancing FG and CACM Code.
- Chapter 3 provides an overview of the current regulatory framework and a high level gap analysis of the Greek market with focus on the EU Target Model.
- Chapter 4 presents a high level gap analysis for Italy and the countries on Greece's northern borders.
- Chapter 5 presents our three proposed market models for Greece to comply with the requirements of the Target Model.
- Chapter 6 details the changes needed, advantages and disadvantages of moving from the current Greek arrangements to each of our compliance options.

This report also contains a number of Annexes that act as supporting material to the main report. The annexes include additional background information on the following areas:

- Annex A provides more description of the concepts of price and volume coupling;
- Annex B sets out the roles and responsibilities proposed for different stakeholders under two commercial market coupling initiatives;
- Annex C summarises the key features of the price coupling algorithm being developed for the Price Coupling of the Regions Project (PCR);
- Annex D summarises the key roles of the various stakeholders in a new market framework; and
- Annex E provides more detail on the discussion of the Imbalance Settlement as per the current Greek market arrangements.

1.3 Conventions on sources

Unless otherwise attributed the source for all tables, figures and charts is Pöyry Management Consulting.

1.4 Glossary

In order to guide readers of this report, we describe below the meaning of the key terms as used for this report:

- **ACER** – Agency for the Cooperation of Energy Regulators, established in March 2011 as part of the implementation of the Third Energy Package.
- **Balancing Energy** – "energy (MWh) activated by TSOs to maintain the balance between injections and withdrawals" (Section 1.3 of the draft EB FG).
- **Balancing Reserves** – "power capacities (MW) available for TSOs to balance the system in real time" (Section 1.3 of the draft EB FG).
- **BRP** – a Balance Responsible Party is "a market participant or its chosen representative, responsible for its imbalances" (Section 1.3 of the draft EB FG).
- **CACM** – Capacity Allocation and Congestion Management in relation to interconnectors.
- **CACM FG –** the CACM Framework Guidelines issued by ACER in July 2011 and approved by the European Commission in September 2011.
- **(draft) CACM NC** – the July 2012 draft of the CACM Network Code issued by ENTSO-E.
- **CAM** – the Capacity Adequacy Mechanism currently in place in Greece.
- **CWE** – the Central West Europe region includes Germany, France, Belgium, the Netherlands and Luxembourg.
- **DAM** – a Day Ahead Market used for price coupling in compliance with the Target Model.
- **DAS** – the Day Ahead Schedule currently used in the Greek electricity market.
- **(draft) EB FG** – the draft Electricity Balancing Framework Guidelines issued by ACER in April 2012.
- **ENTSO-E** – the European Network of Transmission System Operators for Electricity.

- **IDM** – the Intraday Market used for (continuous) price coupling in compliance with the Target Model.
- **(Uninstructed) Imbalances –** defined for the purposes of this report as "deviations between generation, consumption and market deals … of a BRP within a given imbalance settlement period" (Section 1.3 of the EB FG) and can be considered as comparable to 'uninstructed deviations' under the current Greek market arrangements.
- **Imbalance settlement** – defined for the purposes of this report as a "financial settlement mechanism aimed at recovering the costs of balancing applicable to imbalances of BRPs" (Section 1.3 of the EB FG).
- **Interconnector** – denotes an electricity link between Bidding Zones (which could include a zone within an EU member state), rather than necessarily between EU member states.
- **Market Time** – "Central European Summer Time or Central European Time, whichever is in effect. In essence, it is the local time in Brussels" (July 2012 draft of CACM NC.
- **NEMO** – National Electricity Market Operator to whom specific responsibilities are assigned under the July 2012 draft of the CACM NC.
- **NRA –** National Regulatory Authority (i.e. the energy regulator for a particular country).
- **NTC** – Net Transfer Capacity is the method most commonly used at present to calculate the available capacity on an interconnector.
- **NWE** – North West Europe.
- **Pool** – the (gross mandatory) pool currently used in Greece, unless otherwise specified (i.e Hybrid option)
- **Target Model** – a set of principles, primarily in relation to allocation of and use of interconnector capacity, designed to facilitate progress towards a single European electricity market.
- **(Bidding) Zone** – "the largest geographical area within which Market Participants are able to exchange energy without Capacity Allocation. Each generation and load unit shall belong to only one Bidding Zone for each Market Time Period" (Article 2 of the draft CACM NC).
- **CBA** – Cost Benefit Analysis.

2. EUROPEAN ELECTRICITY TARGET MODEL

The development of a single European electricity market by 2014 is a major theme of the Third Package[6] of European energy legislation, which came into force in March 2011. The rules for market integration are based around the European Target Model for electricity, which is described in this Chapter and is strongly influenced by the markets of North West Europe.

This raises significant challenges for the Greek market whose design is fundamentally different from the approach used in North West Europe. To a large extent, these differences reflect the particular challenges for Greece in maintaining a secure supply and mitigating market power. Chapter 3 looks in more detail at the major gaps between the Target Model and the existing Greek market arrangements.

2.1 European policy context

The development of more integrated European electricity and gas markets across Europe is a major theme of the Third Package of European energy legislation. This is designed to facilitate the efficient transfer of electricity (and gas) across Europe to deliver electricity supplies that are:

- **secure** as a bigger market should provide greater diversity in generation and demand;
- **low-carbon** through facilitating the integration of high renewables to meet 2020 targets and beyond; and
- **affordable** by allowing more efficient use of resources, both networks and generation, and encouraging greater competition in electricity markets.

The development of European Network Codes ('NCs') is one of the key tools introduced by the Third Package for the deepening of electricity market integration. Figure 7 illustrates the responsibilities of different European bodies in creating a legally binding NC (in the form of a European Regulation). At each stage, the European Commission has an oversight and coordinating role of the whole process.

Figure 8 summarises the state of development of the NCs currently under development, which can be grouped under four different headings – grid connection, capacity allocation and congestion management ('CACM'), balancing, and system operation.

This report looks at the implications for the design of the Greek electricity market of the (draft) Framework Guidelines (FGs) and NCs for CACM and balancing. These FGs and NCs are expected to have the biggest implications for electricity market design across Europe because they are intended to support a move to the European Target Model for electricity. The Target Model is focused on the allocation and use of capacity on electricity interconnectors, reflecting the fact that the inefficient use of transmission network capacity is seen as major barrier to delivery of a single electricity market.

The FGs and NCs on grid connection and system operation are more technical in nature, each having implications for a particular industry group; e.g. the Requirements for Generators Code (RFG), the Demand Connection Code.

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6 Published in the Official Journal of the European Communities on 14 August 2009, the provisions of the Third Package came into force on 2 March 2011.

Figure 7 – Overview of process for developing European Network Codes for electricity

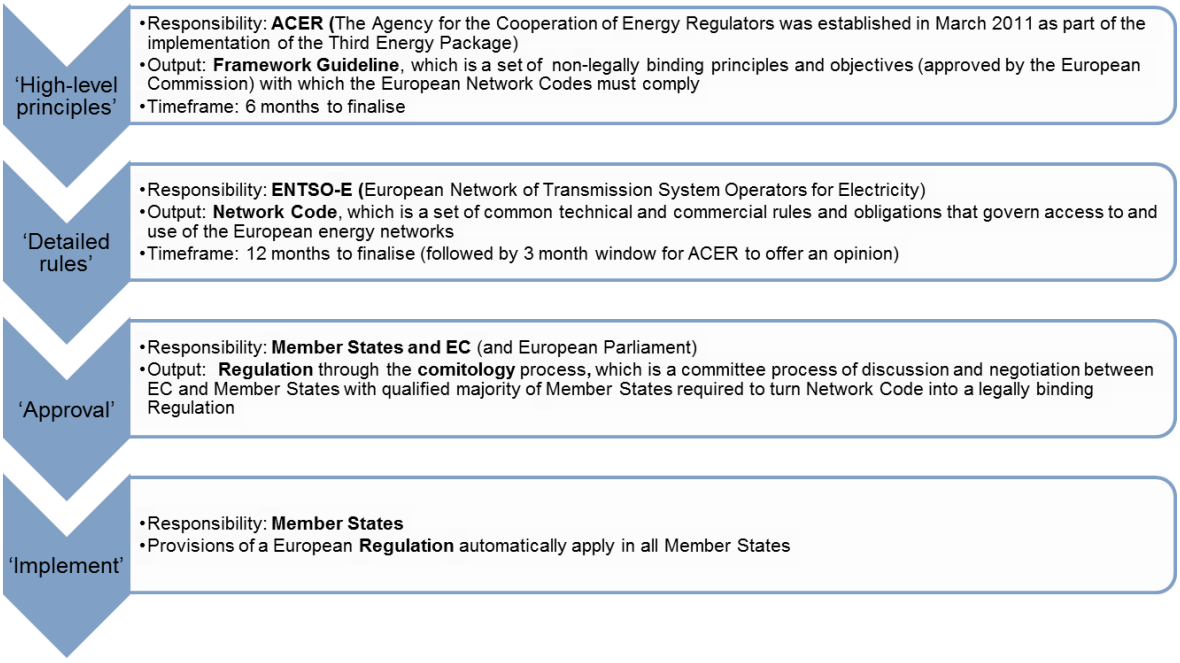
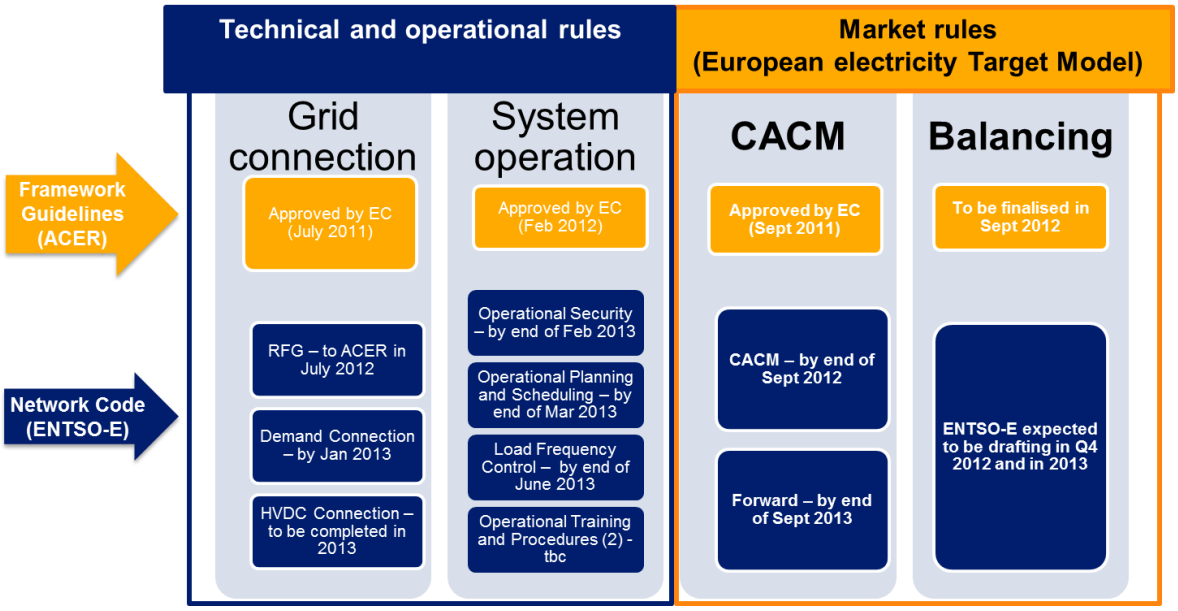


Figure 8 – European Network Codes for Electricity



2.2 Development of European rules for the Target Model

In September 2011[7], the EC approved the CACM FG published by ACER[8], asking ENTSO-E to draft the CACM NC (but not the Forward NC) by the end of September 2012[9]. ENTSO-E has subsequently published two draft versions of the CACM NC – for formal consultation between March and May 2012[10], and as an update after consultation in July 2012[11].

Table 6 summarises the key issues raised by the CACM FG, which are considered in more detail in the subsequent sections.

Table 6 – Summary of NCs to be developed in response to CACM FG

Network Code	Objective	ENTSO-E drafting	Key issues
CACM	'to ensure optimal use of transmission network capacity in a coordinated way'	Q4 2011 – Q3 2012	Method for calculating capacity – flow-based or NTC? (Re) definition of zones (and scope for sub-national markets).
Forward	'to achieve efficient forward market for capacity allocation'	Q4 2012 – Q3 2013	Definition of transmission rights – physical or financial (one way or two way)?
CACM	'to achieve reliable prices and liquidity in the Day Ahead capacity allocation'	Q4 2011 – Q3 2012	Implementation of price coupling (whereby market prices and interconnector flows are determined by single algorithm).
CACM	'to design efficient intraday market capacity allocation'	Q4 2011 – Q3 2012	Implementation of implicit continuous allocation of interconnector capacity (which can be supported through periodic auctions).

The CACM FG and the associated NCs (CACM, Forward) are designed to support the implementation of the Target Model for electricity. As the Target Model directly refers to the transfer of electricity between zones, it does not require a specific market design for all European electricity markets. However, the Target Model has been developed based on the North West European electricity markets, which have decentralised arrangements for scheduling and dispatch.

7 'European Commission request for ENTSO-E to start drafting the CACM NC', EC, 19 September 2011.

8 'Framework Guidelines on Capacity Allocation and Congestion Management for Electricity. FG-2011-E-002', ACER, 29 July 2011.

9 The network codes would then be evaluated by ACER before entering the comitology process ahead of the scheduled implementation date of 2014.

10 'Network Code on Capacity Allocation and Congestion Management. Draft for Consultation', ENTSO-E, 23 March 2012.

11 'Network Code on Capacity Allocation and Congestion Management. Updated Draft following Consultation', ENTSO-E, 16 July 2012.

The role of such arrangements in the Target Model is illustrated by the following statement on the role of intraday trading in Section 5 of the CACM FG:

"The key feature of the intraday market is to enable market participants to trade energy as close to real-time as possible in order to (re-)balance their position. Intraday trading is particularly important to accommodate intermittent generation and unexpected events such as outages."

This raises significant challenges for the Greek market whose design is fundamentally different from the approach used in North West Europe, including a reliance on the TSO (rather than market participants) to respond to developments over the intraday timescale.

2.2.1 Electricity Balancing FG

ACER is currently developing a specific FG on electricity balancing ('EB FG'), as shown in Figure 8. This has included a consultation on a draft version[12] between April and June 2012, and a public workshop in May 2012[13].

The draft EB FG sets out the requirements for the balancing NCs to harmonise the following areas (in line with the January 2012 invitation from the EC to start drafting the EB FG)[14]:

- definitions, roles and responsibilities (Section 2);
- procurement of balancing services, in particular facilitation of competition across balancing areas through compatible products and timeframes, and harmonised rules for remuneration of offers (Section 3);
- access to interconnector capacities for the purposes of balancing (Section 4); and
- arrangements for (uninstructed) imbalance settlement, relating to the incentives for market participants to deliver a balanced system outside of reserve provision (Section 5).

As a general note, it is important to recognise that the EC and ACER have both highlighted the need to consider the scope for the demand-side in providing reserves and the treatment of intermittent generation in imbalance settlement.

The EB FG defines 'balancing' as *"all actions and processes through which TSOs ensure that the total electricity withdrawals are equalled by the total injections in a continuous way, in order to maintain the system frequency within a predefined stability range."*

This highlights the focus on the EB FG on actions rather than the 'balancing' timescale, where it is typically that a TSO acts as a single buyer (or seller) in a balancing area to ensure that generation equals demand in real time.

The EB FG considers two components to the balancing services available to a TSO – (balancing) reserves and balancing energy – which are provided by a Balance Service

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12 'Framework Guidelines on Electricity Balancing. Draft for consultation. DFGEB-2012-E-004,' ACER, 24 April 2012.

13 http://www.acer.europa.eu/Media/Events/Presentation_of_the_Draft_FG_on_Electricity_Balancing/default.aspx

14 'Electricity Balancing Framework Guidelines. Presentation of Draft for consultation and Initial Impact Assessment', ACER, 29 May 2012.

Provider (BSP). At a high-level, these services can be differentiated as follows. Balancing reserves are available to the TSO to help manage the system, but balancing energy is what is actually used by the TSOs (e.g. to respond to an unexpected outage).

Section 1.3 of the draft EB FG defines three types of reserve (presented below in order of speed of response) as described in:

Table 7 – Reserve types defined in draft Electricity Balancing Framework Guidelines

	Frequency containment reserves	Frequency restoration reserves	Replacement reserves
Purpose	Constant containment of frequency deviations	Restore frequency and power balance after sudden system imbalance	Restore required level of operating reserves to be prepared for a further system imbalance
Activation time	Up to 30 seconds	Up to 15 minutes (varies by synchronous area)	From 15 minutes up to hours
Activation method	Automatic	Automatic or manual	Manual
Activation location	Local	Central	Central

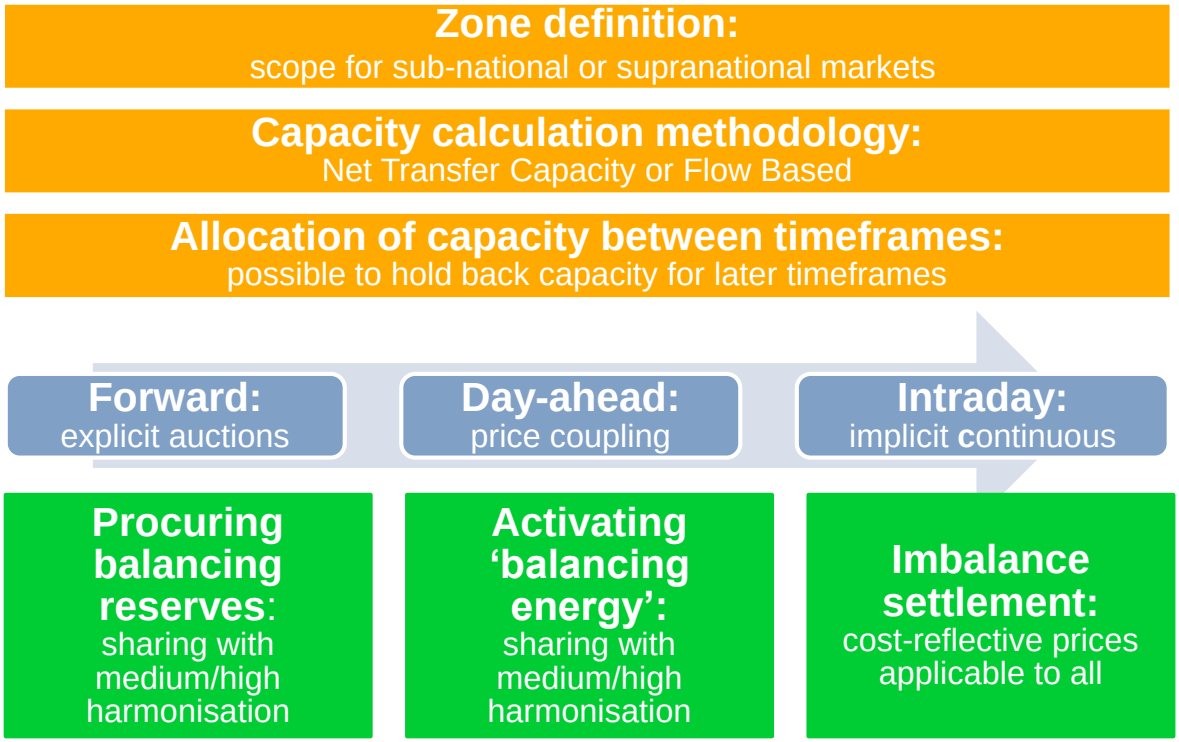
Sections 2.3.8 to 2.3.10 look at the detailed requirements of the draft EBFG for our three building blocks in relation to balancing:

- procuring balancing reserves;
- activating balancing energy; and
- imbalance settlement.

2.3 Description of Target Model

We describe the European Target Model for electricity in terms of the nine building blocks that we introduced in Section 1.1.1. Figure 9 provides a high-level summary and we then look at each building block in more detail in the subsequent sections. The Target Model was initially developed in relation to the allocation and use of interconnector capacity in relation to energy market trading (forward, day ahead and intraday). Therefore, we have interpreted the principles set out in the draft EB FG as representing the Target Model in relation to balancing.

Figure 9 – Building block summary of Target Model



2.3.1 Zone definition

The Target Model is designed to provide a single market rather a single price across Europe in all periods, although the Target Model should deliver greater (if incomplete) price convergence than the current arrangements.

Indeed, the Target Model is structured around the concept that differences in zonal prices provide important locational signals for the operation of and investment in demand, generation and networks. For example, Section 2.2 of the CACM FG states that *"The definition of zones shall further contribute towards correct price signals, and support adequate treatment of internal congestion".*

It is expected that one single clearing price in the Day Ahead Market will apply in each Bidding Zone (or 'zone'), which is defined in Article 2 of the July 2012 draft of the CACM NC as *"the largest geographical area within which Market Participants are able to exchange energy without Capacity Allocation. Each generation and load unit shall belong to only one Bidding Zone for each Market Time Period."*

One of the key areas of debate on zone definition has been the proposed requirements for a regular review of zone definition. The CACM FG states that the CACM NC shall require TSOs to provide NRAs (and ACER) with a regional analysis of the existing zones every two years. Chapter 2 (Articles 39-43) of the July 2012 draft of the CACM NC also discusses this review process, which (as listed in Article 40) will consider:

- network security;
- market efficiency, including market power and market liquidity, impact on imbalance settlement, and the need for redispatch/counter-trading; and

- stability and robustness of zones over time.

Under the provisions of the Target Model, limiting transmission capacity between zones to solve internal congestion is generally banned, with any incidences to be reported transparently.

This is in addition to possible powers under European competition law – for example, action by the EC Competition Directorate (DGCOMP) resulted in the splitting of the Swedish electricity market into four zones in November 2011 (as part of the agreed remedies in a competition case against the Swedish TSO Svenska Kraftnät). The splitting into zones is designed to allow the TSO to handle internal congestions in the Swedish transmission grid without moving the internal limitations to the border.

2.3.2 Capacity calculation methodology

The Target Model allows two alternative methodologies for calculation of transmission capacity between zones – (coordinated) Net Transfer Capacity (NTC) and Flow Based.

The Flow Based approach uses simultaneous optimisation of allocation of capacity between zonal borders, and allocation of capacity according to energy flows. The CACM FG states that a FB approach is preferred for short-term capacity calculation for highly meshed networks with highly interdependent interconnections. For example, its introduction is being considered in the CWE region[15].

Section 2.1.1 of the CACM FG states that, provided that it is done in a coordinated way, NTC is an acceptable methodology for short-term capacity calculation:

- for less meshed networks (e.g. Nordic market); or
- between large peninsulas and/or islands in Europe.

It is possible that Greece could be defined in either of these categories. However, as far as we are aware, no formal confirmation has been published stating whether or not Greece would be defined to be in either (or both) categories. We note the view of the TSO that there is a strong interdependency between the interconnectors between Greece and the countries on its Northern borders. Consequently, capacity calculation on these interconnectors should be subject to coordinated NTC evaluation, if a Flow Based methodology is not applied.

The preference for the use of Flow Based is reflected in the draft CACM NC[16], which states that Flow Based will be used for all regions except where:

- distribution of power flows is not highly influenced by cross-zonal exchanges in other regions; or
- Flow Based would not ensure system security (given the particular circumstances of the region), increase social welfare (in the relevant region), and/or allow market participants sufficient time to adapt their process.

Under either methodology, the Target Model requires that available maximum flows (under Flow Based) or the NTC are reassessed sufficiently often intraday to respond to events close to real-time, such as generation outages or changes in wind forecast.

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15 http://www.elia.be/en/projects/market-integration/flow-based-marktkoppeling-centr-w-europa#anchor2

16 Article 26 of July 2012 draft.

There is scope for interconnector losses to be taken into account in the 'Allocation Constraints' considered both in the capacity calculation process and in the market coupling algorithm[17]. Losses are likely to be a material issue on subsea interconnectors, such as the link between Italy and Greece.

2.3.3 Allocation of capacity between timeframes

European energy regulators have historically been worried about allowing TSOs to hold interconnection capacity back for use in later timeframes, particularly for balancing. This reflects concerns that holding capacity back could distort the utilisation of interconnector capacity and hence, price differentials (generally, to the benefit of the TSOs themselves as it would reduce the cost of their system balancing costs).

As a result, Section 4.2 of the CACM FG gives national regulators a role in reviewing and approving *"the volume of yearly capacity rights, as well as the principles for sharing capacity between the different time frames".*

Section 4.3 of the draft version of the EB FG[18] allows for reservation of interconnector capacity for balancing purposes subject to a positive cost-benefit analysis. Section 4.2 specifies that there would be no charge for the use of interconnector capacity for exchange of balancing energy after intraday gate closure[19].

2.3.4 Long-term transmission rights[20]

The CACM FG raise two key issues for the allocation of long-term transmission rights[21]:

- **the platform for (re)trading of rights** – Section 4.2 of the CACM FG sets out a requirement for the TSOs to provide a single European platform for the initial allocation of rights and for anonymous secondary trading of these rights; and
- **the type of long-term[22] transmission right** – which Section 4.1 of the CACM FG allows to be physical or financial, unless there is appropriate cross-border financial hedging available in liquid financial markets on both sides of an interconnector.

Under the September 2011 mandate it received from the EC, ENTSO-E is not required to formally start drafting the detailed rules around forward transmission rights until October 2012. This means that the deadline for completion of the Forward NC is the end of September 2013.

In the meantime, work continues on the definition and scope of transmission rights ahead of the start of the formal drafting process. For example, in July 2012, ENTSO-E issued an Educational paper on the following 'transmission risk hedging products':

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17 Article 24.2, Article 30 and Article 48 in July 2012 draft of CACM NC.

18 Article 4.3 in draft EB FG

19 Although the draft EB FG notes that this may not apply to exempted interconnectors.

20 Any physical rights would be subject to 'Use It or Sell It' provisions, so that all unused capacity is made available to the day-ahead auction. No such provisions would be needed for financial rights, as they do not imply any right to nominate a flow (or an intention to flow) across the interconnector.

21 These are in addition to the issue around allocation of capacity between timeframes as discussed in Section 2.3.3 of this report.

22 'Long-term' means any period longer than a day, ranging from a week out to multi-year holdings.

- physical transmission right;
- financial transmission right option;
- financial transmission right obligation; and
- Contracts for Difference (CfD) and system price derivatives[23].

ACER issued a consultation paper on the products in August 2012, to help identify which of these products would be best suited to implement the CACM FG provisions with respect to long-term transmission rights.

Figure 10 summarises the main differences between financial and physical transmission rights.

Figure 10 – Types of long-term transmission right

Physical Transmission Right (PTR)	Financial Transmission Rights (FTR)
• right to nominate (intention to) flow	• no right to nominate (intention to) flow
• requires Use-It-Or-Sell-it (UIOSI)	• can be option (one-way) or obligation (two-way)
• full financial resale value given to holder	• full financial value given to rights holder

2.3.5 Day-ahead price coupling

At the heart of the Target Model is the concept of price coupling, both at the Day Ahead and intraday stages. Price coupling is a form of implicit auction, which means that available interconnection capacity and energy flows are effectively traded together (as opposed to an explicit auction used for long-term rights in which interconnection capacity is sold as a separate product from energy flows).

Price coupling is based on a single algorithm that uses bid/offer information from each zone and the available cross border capacities. The algorithm jointly establishes prices, generation volumes and interconnector flows for each coupled market, taking into consideration all bids/offers from all markets.

Day Ahead price coupling arrangements are already in place for a number of markets including (but not limited to) the CWE market and NordPool. Day Ahead price coupling is also used to allocate capacity on the link between Italy and Slovenia.

23 Where the underlying value is the price difference between two reference prices, typically a "price area" price and a "system" price (e.g. as used in the Nordic market).

The implementation of price coupling across Europe is expected to increase the overall efficiency of interconnector utilisation by ensuring that electricity flows from low price zones to high price zones. This increase in efficiency is based on the assumption that comparable prices are produced for all zones.

Under Day Ahead price coupling, there is a one-shot auction, whereby a single algorithm simultaneously determines zonal prices, generation volumes, and interconnector flows.

The amount of interconnection capacity for Day Ahead market coupling is determined by:

- the physical interconnection capacity;
- the amount of long-term physical rights allocated (if any); and
- the residual capacity available, after nomination against the physical capacity rights (if any) prior to the Day Ahead market coupling

Because flow and prices are calculated in a one-step process, they should be consistent. In contrast, under volume coupling which uses a two-step process (as a single algorithm determines interconnector flows which go into separate auctions to determine the price for each zone), there has been experience of inconsistent flows and prices (i.e. flows from high price zones to low price zones) – one example on this was on the initial launch of volume coupling between Germany and Denmark.

We have identified the following requirements which will need to be met by a Greek Day Ahead Market (DAM) to comply with the Target Model (based on Section 3 of the CACM FG, and Chapter 4 (Articles 48 – 61) of the July 2012 draft CACM NC):

- **All available interconnection capacity to be allocated through a single price coupling algorithm[24] based on the marginal pricing principle;** with available Cross Zonal (or interconnector) Capacities to be published by 1100 Market Time[25] (1200 Greek time).on D-1 (Article 56).
- **Common gate closure times**; Day Ahead gate closure is proposed to be at 1200 Market Time (1300 Greek time) on D-1 (Article 57) with Scheduled Exchanges to be notified to TSOs by 1530 Market Time (1630 Greek time) on D-1 along with publication of market information (Article 61).
- **Common bid format** - the price coupler will accept a common set of bid formats, based on consultation between the Market Coupling Operators, Market Participants, TSOs and NRAs (Article 51). The Price Coupling of the Regions project is still finalising the full list of bid formats (discussed in more detail in Annex C). Although provision will be made for different forms of 'block bids' (as required by the CACM FG), these are unlikely to encompass the full sophistication of the technical and commercial offer data currently used in the Day Ahead schedule in Greece (as discussed in more detail in Chapter 3 of this report).
- **Comparable energy market prices –** in most other European markets, the Day Ahead price (currently[26]) is an 'all-in' price (e.g. covering both energy[27] and capacity).

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24 Which will be required (amongst other things) to *"maximise economic surplus for the price coupled region for the subsequent trading day"* (Article 48 of July 2012 draft of CACM NC).

25 The July 2012 draft CACM NC defines **Market Time** as *"Central European Summer Time or Central European Time, whichever is in effect. In essence, it is the local time in Brussels".*

26 Although other countries, such as Italy, France (under the NOME law) and GB (under the EMR proposals) are proposing to introduce more explicit capacity mechanisms into their market design, these capacity mechanisms will not necessarily be based around a separate

In addition, Article 50 of the draft CACM NC allows for harmonisation of maximum and minimum bid prices to apply in all Bidding Zones[28].

- **Pricing of interconnector capacity at Day Ahead stage** – must be determined by the difference between clearing Day Ahead price in each zone (Article 52).
- **Firmness of Day Ahead (and Intraday) capacity**[29].

In addition, the nature of the Day Ahead market is that both buyers and sellers participate actively in terms of submitting firm pricing offers and bids to the operator of the local Day Ahead market, who would then be responsible for providing bids and offers in an acceptable form to the central market coupling algorithm. For the market to be successful, suppliers (or some representative body) must actively submit priced bids and accept firm contracts as a result. We note that Article 2 of the July 2012 draft of the CACM NC allows for TSOs and/or PXs (and their designated entities) to be defined as a Market Participant (whilst respecting the applicable Regulation).

Annex B contains a description of the key features of the commercial initiatives to implement Day Ahead market coupling across much of Europe. The first delivery of this will be for the NWE (North-West Europe) region, but this is based on the algorithm developed as part of the PCR (Price Coupling of Regions) project which also covers the CWE and CSE regions so it will in the next step also include Spain and Italy.

2.3.6 Continuous intraday trading with pricing of congestion

The effective operation of intraday trading through implicit auctions[30] is seen as important in allowing participants to fine-tune positions close to real-time, e.g. in response to outages and variable generation (and demand).

The key requirements for intraday set out in Section 5 of the CACM FG are for continuous implicit trading with pricing of interconnector capacity (to reflect congestion).

We have identified the following requirements which will need to be met by a Greek intraday market (IDM) to comply with the Target Model (based on Section 5 of the CACM FG, and Chapter 5 (Articles 62 – 71) of the July 2012 draft CACM NC):

- **Continuous implicit trading** (Articles 62 and 63).
- **Pricing of interconnector capacity to reflect congestion** (Article 65).
- **Comparable energy market products and prices –** scope for harmonisation of maximum and minimum bid prices to apply in all Bidding Zones (Article 64)[31].

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capacity payment for the whole. For example, the capacity mechanism in France may be based around a capacity obligation on suppliers.

27 Inclusive of start and no load costs as far as is possible.

28 Where the existing maximum and minimum prices fail to facilitate the objectives of the Day Ahead Price Coupling Algorithm, or of the CACM NC more generally.

29 Paragraph 29 of Purpose and Objectives in July 2012 draft of CACM NC.

30 The CACM FG (Section 5) and the July 2012 draft CACM NC (Articles 91-95) both allow explicit allocation of capacity intraday as a transitional measure to facilitate OTC trades, subject to the 'approval' of the NRAs.

31 Where the existing maximum and minimum prices fail to facilitate the objectives of the Day Ahead Price Coupling Algorithm, or of the CACM NC more generally.

- **Harmonised gate closure time –** a maximum of one hour prior to the start of the relevant time period (Article 67), with Cross Zonal Capacity and Allocation Constraints be provided to the Market Coupling Operator no later than 15 minutes prior to Intraday Cross Zonal Gate Opening Time (Article 66).
- **Shared order book**[32] (Article 62) **and capacity management module** (Article 71) – both being on a pan-European basis, and with a one to one relationship.
- **ensure all intraday cross-zonal capacity to be allocated via the pan-European platform**.
- **describe a process for establish clear rules on process and timings for recalculation and updating of intraday capacity**.
- **foresee that intraday capacity is firm (and its use obligatory) once allocated**.

There are also provisions for supporting periodic auctions to complement the implicit continuous trading, both in the CACM FG (Section 5) and in the July 2012 draft CACM NC (Article 71). The CACM FG (Section 2) and July 2012 draft CACM NC (Articles 91-95) also sets out the possibility for transitional arrangements that allow explicit capacity access intraday, for example, for bilateral contracts (until sufficiently sophisticated products) have been developed.

The major challenge for the Target Model for the IDM is that the approach proposed under the CACM FG is not as well established (or as clearly defined) as for the DAM. To a large extent, this reflects the fact that the IDM has been less important in a number of the key markets, such as the Nordic market. In addition, there is a tension between continuous trading[33] and congestion pricing[34] - the two major requirements for the intraday solution - which are not seen together in existing European electricity market designs. For example, the Nordic market has continuous intraday trading but no provision for the pricing of intraday congestion.

This means that one of the interesting areas that has to be explored further in designing the detailed rules for the Target Model (at a European level) is how to reveal value for intra-day capacity, given the chosen route of continuous intra-day trading, and the need for pricing to reflect actual trades.

Our understanding is that ENTSO-E is currently considering two options:

- at the opening of the intraday auction (although this does not reflect subsequent trading based on updated information); and
- when additional Cross Zonal capacity is released to the market (although this may not occur).

Both of these options take advantage of the fact that there are times where continuous trading has similar characteristics to a periodic auction (i.e. there is a block of trades that could be matched and a block of available capacity).

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32 A shared order book would cover all bids submitted to all participating PXs and intraday platforms, and would be based around a unique algorithm. Article 62 of the July 2012 draft CACM NC sets out objectives for this algorithm, which are broadly in line with the objectives for the DAM algorithm in Article 48.

33 Article 62 of the July 2012 Draft CACM NC.

34 Article 65 of the July 2012 Draft CACM NC.

We also consider that there are two other alternative options that may merit consideration. The first is to introduce arrangements under which there is trading of firm energy and options to deliver energy (for the same hour) exercisable with 1/2/3/4/5 etc hours notice. This would allow the use of a co-optimisation algorithm to allocate and price the capacity. Trading of cross-border reserve products may be a step forward towards this solution as the intention is to co-optimise energy and reserve.

Alternatively, the periodic intraday auctions could be used to price congestion – however these auctions are required to only 'complement' the continuous intraday trading, where there is sufficient liquidity. We also understand that there are concerns about whether the existing intraday auction software used in some markets could be run fast enough for auctions with 1 hour gate closure.

2.3.7 Balancing

The subsequent sections (2.3.8 to 2.3.10) look at the detailed requirements of the draft EBFG for our three building blocks in relation to balancing:

- procuring balancing reserves;
- activating balancing energy; and
- imbalance settlement.

Before looking at the detailed requirements, it is helpful to consider the context for the Target Model with respect to balancing, which is at a less detailed stage of development than for the allocation and use of interconnector capacity through wholesale electricity market trading (CACM). This reflects both the fact that the Target Model was initially developed with respect to the wholesale electricity market, and that the EB FG are still yet to be submitted to the EC for approval (as of 17 September 2012).

Furthermore, the requirements of the Target Model for balancing are not expected to be binding by 2014, the date set by European governments for the launch of a single electricity market.

Section 1.4 of the draft EB FG sets out provisions for transition periods between the publication of the Balancing NCs and the application of the requirements (albeit with no grandfathering for existing arrangements after the end of the transition period). Section 1.5 of the draft EBFG also specifically sets out scope for the NRAs to grant derogations for up to 2 years from the requirements of the Balancing NCs to reflect either significant differences in balancing arrangements or significant problems in balancing the system whilst meeting the requirements of the NCs.

A key thrust of the Target Model (as set out in the draft EB FG) is to support greater sharing of balancing resources between TSOs. Figure 11 summarises the four options for sharing balancing resources discussed in the Initial Impact Assessment supporting the draft EB FG[35].

[35] 'Framework Guidelines on Electricity Balancing. Initial Impact Assessment. Draft. DFGEB'. ACER, 24 April 2012.

Figure 11 – Options for procuring and activating balancing reserves (as discussed in supporting document on Balancing FG)

A	**Status quo**	• Continuation of current voluntary approach
B	**European exchange with minimum harmonization requirements**	• Exchanges of surpluses - both energy and reserve • Identification of selected cross border products to be exchanged
C	**European balancing services exchange with medium/high level of harmonization**	• **Every available resource (considering network constraints) is shared in the common merit order** **Key elements would be harmonized e.g. products, PTU, GCT etc…**
D	**Single European balancing mechanism – possible "supranational TSOs"**	• Market design harmonized (BSP, BRP, procurement and settlement) at least at synchronous area level

The draft EB FG propose a move to Option C in the short to medium term (Section 3.2.2), which would be supported for example by harmonised gate closure times and sharing of forecast data between TSOs (Section 3.2.1). Under this option, the TSOs may hold back some of their most expensive balancing bids from the common merit order list, in order to provide a national 'margin'. The Balancing NCs will specify the principle of determining the size of this margin.

Option C is an interim step as the long-term aim under the Target Model is to introduce full sharing arrangements in line with Option D, which can be seen as analogous to energy market coupling. The draft EB FG sets out that Option D should be implemented within seven years after the entry into force of the Balancing NCs (Section 3.2.2).

2.3.8 Procuring balancing reserves

The draft EB FG (Section 1.3) define (balancing) reserves as being *"power capacities (MW) available for TSOs to balance the system in real time."*

The key requirements set out in Section 3 of the EB FG in relation to the procurement of these reserves are as follows:

- harmonisation of products (with possible local specificities);
- common principles for the procurement process; and
- coordination between TSOs for the sizing of reserve requirements, according to the provisions of the Load Frequency NC being drafted by ENTSO-E.

Section 4.3 of the draft EB FG discusses the impact of cross-border exchanges of reserves, which could materialise as a higher reserve margin or a specific cross-border reservation, which is only allowed where it can be demonstrated to increase overall social welfare under a robust cost-benefit analysis.

2.3.9 Activating balancing energy

The draft EB FG (Section 1.3) define balancing energy as *"energy (MWh) activated by TSOs to maintain the balance between injections and withdrawals."* The activation can be manual or automatic, and can use (but is not limited to) resources made available through a payment for availability from the TSO (i.e. procured reserves)

The key requirements for the activation of balancing energy set out in the draft EB FG are as follows:

- harmonisation of products (with possible local specificities);
- common principles for the selection process, namely a 'Merit Order List' which ranks all valid balancing bids in order of bid prices;
- common principles for the pricing method, namely marginal pricing; and
- harmonisation of intraday gate closure times, as close to real time as possible (which obviously has interaction with the provisions of the CACM NC).

2.3.10 Imbalance settlement

Section 1.3 of the draft EB FG defines 'imbalances' as *"deviations between generation, consumption and market deals … of a BRP)*[36] *within a given imbalance settlement period".* In the context of the Greek market, this can be considered as referring to uninstructed imbalances[37], (defined through the interaction between 3 quantities – dispatch, metered volumes, and position in the DAS).

The market deals are defined as covering all timeframes, and including sales and purchases on organised markets or between BRPs. Our understanding is that markets should cover wholesale electricity markets and 'balancing/reserve' markets. This means that in the Greek context, the final dispatch decision for a generator is the outcome of the market deals.

This is consistent with the definition of Imbalance Settlement (in Section 1.3 of the draft EB FG) as *"a financial settlement mechanism aimed at recovering the costs of balancing applicable to imbalances of BRPs."*

The April 2012 draft EB FG set out the aim for the Balancing NCs to ensure that imbalance settlement rules are defined in a way that support competition and there are limited distortions resulting from differing settlement mechanisms in adjacent markets. In particular, Sections 5.2 and 5.3 of the EB FG identified the following aspects for harmonisation:

- BRPs will be obliged to provide a balanced program in the Day Ahead time frame (although it is unclear what form and strength this obligation will take);
- BRPs will be incentivized to be balanced in real time;
- intermittent renewable generation will not receive special treatment for imbalances, which is consistent with the increased scrutiny on imbalance arrangements for

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36 A Balance Responsible Party (BRP) is defined by the draft EB FG as "*a market participant or its chosen representative, responsible for its imbalances."*

37 By 'uninstructed imbalance' we refer to the difference between the metered quantity and the final dispatch instruction.

intermittent generation (with changes being proposed in Italy for example that would start to apply imbalance arrangements to intermittent generation); and

- the imbalance settlement period shall not be greater than 30 minutes, with ENTSO-E to conduct a cost-benefit analysis on the harmonisation of imbalance settlement period across Europe.

3. ANALYSIS OF THE CURRENT ELECTRICITY MARKET DESIGN IN GREECE

There are a number of common challenges that must be addressed by the design of any electricity market:

- the electricity system must be operated within narrow frequency and voltage limits, and there is very **limited scope for storage**, so **generation must equal demand in real-time**;
- electricity is transported over a shared network, and hence **actions by any party can impact on others**;
- **parties cannot be forced to act in accordance with prior contracts**, which creates potential for unexpected behaviour and need for actions to be taken to balance the system;
- **demand is highly variable** (e.g. in response to time of day, season and weather) **but** is relatively **insensitive to price**; and
- society has come to expect a reliable electricity supply, and **the cost of supply interruptions is high**.

Taken together, the above features mean that there is a greater need for spare capacity to meet peak demand, to respond to unexpected actions and to maintain system security compared with virtually any other traded commodity.

Despite these common challenges, there are a variety of electricity market designs in use across the world reflecting local issues, objectives and philosophies. Therefore, in this Chapter, we first briefly describe the key features of the Greek electricity market structure before describing the current electricity market design. We then set out the results of our analysis of the major gaps between the existing Greek market design and the Target Model (as detailed in Section 2.3).

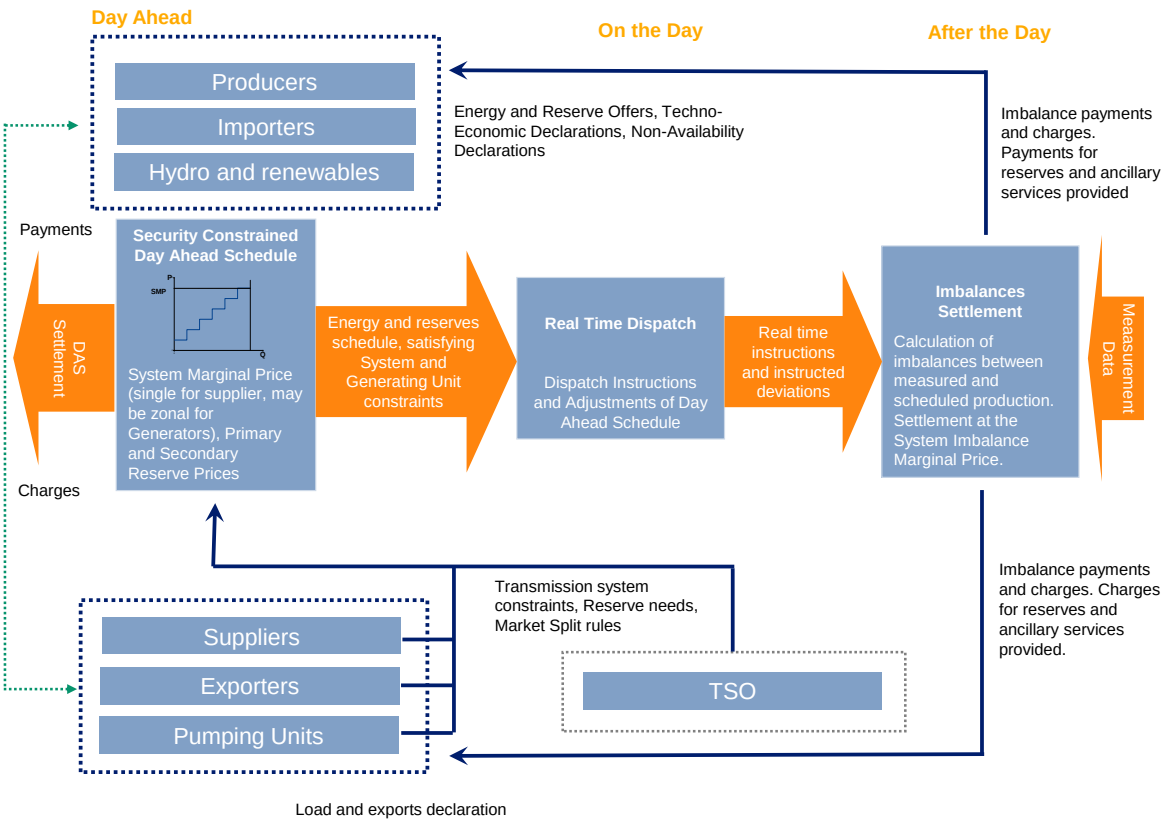
3.1 Overview of current Greek market design

The main features of the current Greek design include:

- a gross mandatory pool (the Pool) which uses a ('technical') algorithm to determine the prices and schedule for the entire energy market - to help encourage new entry by providing a guaranteed route to market and robust reference price;
- co-optimisation of energy and reserves to help maintain security of supply;
- generation inputs into the Pool algorithm include economic bids, cost data (including shut down costs) and technical characteristics of the generator units;
- central dispatch of generation;
- prices produced by ex-post run of Pool algorithm used in settlement of instructed and uninstructed imbalances;
- separate Capacity Adequacy Mechanism (CAM) intended to incentivise new build; and
- Cost Recovery Mechanism – intended to ensure that all units generating upon receiving a dispatch instruction cover at least their costs (plus an additional profit)

Figure 12 summarises the key features of the Greek market, with the Day Ahead Schedule ('DAS') at its heart. The DAS minimises the overall cost of meeting demand for the next day whilst taking account of the need for adequate reserves through a co-optimisation process. The DAS also consider a number of other constraints, such as unit commitment and the need for reliable system operation.

Figure 12 – Overview of the Greek market



3.1.1 *Context for Greek electricity market design*

The existing Greek market design is a response to the key issues faced by the market, in particular the:

- dominance of PPC in generation and retail, which increases importance of market power mitigation measures; and
- geographical balance of supply and demand, which increases importance of considering transmission issues in the market results.

Although Independent Power Producers (IPPs) have increased their share in the market, PPC continues to dominate plant ownership. In recent years, a number of new parties have entered the Greek generation sector (e.g. Mytilineos Holdings, GEK Terna Group, Elpedison). However, this has been limited to gas-fired generation as PPC currently retains exclusive rights to hydro and lignite. PPC also dominates the retail market, with its market share estimated to be well in excess of 90%. Although some new suppliers have entered the market in recent years, they have subsequently exited.

Most of the generation, particularly lignite and hydro-electric, and all of the interconnectors are located in the north of Greece but most of the demand is in the south. Although the

commissioning of new gas-fired generation close to Athens has somewhat evened out the demand and generation mismatch, there is still much importance on the ability of the transmission system to transport electricity from north to south. The capacity of this link is currently 3GW.

In addition to the requirements for Target Model compliance, the future design of the Greek electricity market should also consider the:

- unfavourable economic conditions, which is leading to depressed demand, and increases the importance of credit risk, collateral and cashflow issues;
- strong incumbent in generation and retail, and whilst there is the possibility of structural reforms, these would take time to implement; and
- evolution of the generation mix, and of the import-export balance.

Recent years has seen continued dominance of lignite generation (accounting for about 60% of Greek generation mix since 2004). However, the generation mix is expected to change out to 2020 as a result of climate change policies. Renewable production is projected to increase from current level of 5% in response to European targets. This will increase intermittency challenges faced by the Greek electricity system, making flexibility (e.g. as offered by interconnectors and hydro-electric capacity) increasingly valuable. This flexibility may be able to be provided by sources outside the generation sector (e.g. generation, interconnection, storage and demand-side).

There is also expected to be further growth in gas-fired generation as Greece moves towards full pass-through of CO_2 prices.

Greece has historically been a net importer overall. In particular, it has imported from:

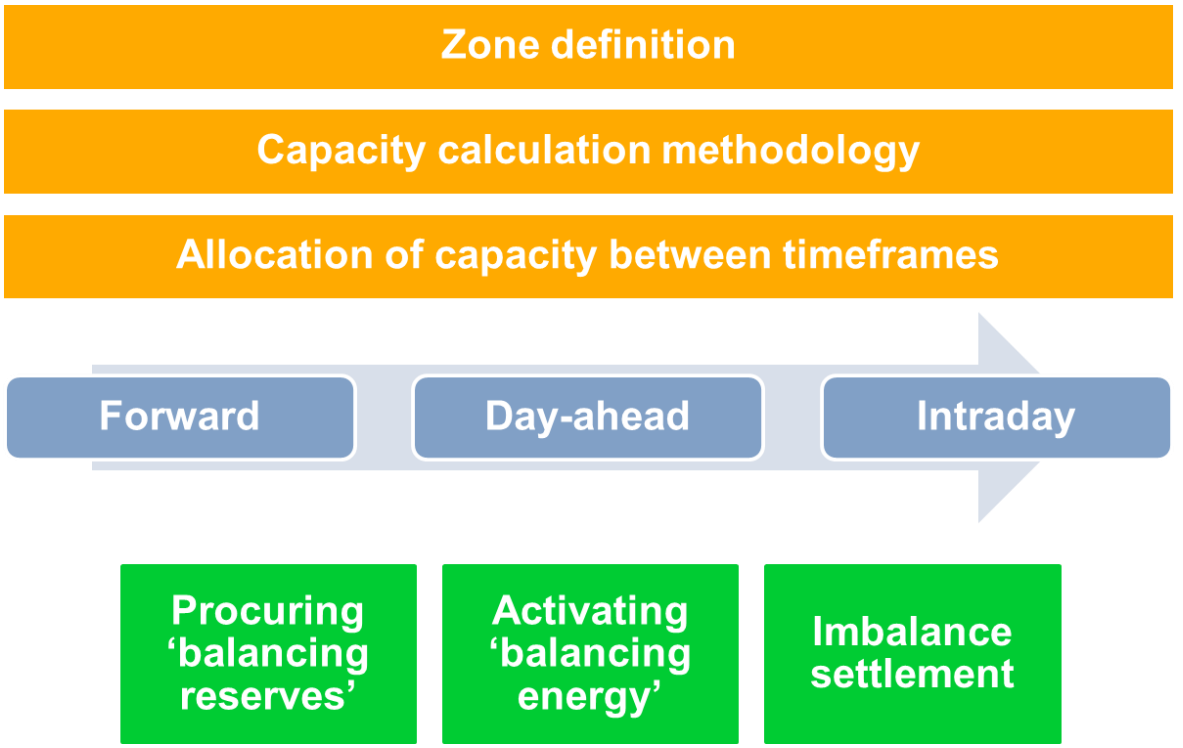
- Bulgaria – driven by lower cost nuclear and hydro generation in Bulgaria;
- FYROM – with imports increasing significantly over last 3 years; and
- Turkey – since the commissioning of the Turkish interconnector in 2011.

On the other hand, Greece has generally exported to Italy and Albania in recent years, although we observe Greece importing from Italy overnight when Italian prices drop significantly. Exports to Italy are typically higher in the winter and have driven by higher Italian gas prices and the cost of green certificates (Certificati Verdi), which feed into Italian wholesale electricity prices. The recent reforms announced to renewable support schemes in Italy will mean that the CV cost drops out of wholesale electricity prices in Italy after 2015, which is likely to reduce the wholesale electricity price in Italy relative to Greece.

3.2 Building blocks of current Greek market design

We now describe the Greek market in terms of the building blocks for market design shown in Figure 13. These building blocks were then introduced in Section 1.1.1, and used to describe the Target Model in Section 2.3.

Figure 13 – Building blocks for description of market design



3.2.1 Zone definition

The DAS currently takes into account transmission network constraints in determining the clearing prices and volumes. There is also an existing provision to implement zonal pricing for generation (e.g. with different prices in north and south of Greece) to provide a locational signal for generation in response to constraints on the transmission system. In those circumstances, there would remain a single national price for demand. This is consistent with the concept of the PUN price for demand in Italy, where there are zonal prices for generation.

Despite this provision, and the fact that the DAS produces zonal clearing prices at times of congestion between northern and southern Greece, a zonal wholesale electricity price for generation has not been implemented in Greece.

3.2.2 Capacity calculation methodology

Our understanding is that the capacity on the Greek interconnectors is calculated using the net transfer capacity (NTC) methodology. We note that ADMIE has already undertaken some analysis of the impact of applying a Flow Based methodology to interconnectors between Greece and other countries.

3.2.3 Allocation of capacity between timeframes

Long-term capacity rights on the Greek interconnectors are allocated through annual and monthly auctions that are organised – individually or jointly – by the TSOs of the countries on either side of the relevant interconnector (i.e ADMIE and/or the foreign TSO). Generally, all of the interconnection capacity is made available through the annual and monthly auctions.

At 0700 (Greek time) on D-1, the holders of long-term capacity rights have to nominate their intention to use their rights (as part of the UIOSI arrangements). All long-term capacity rights that are not nominated for use at this stage (or that were not sold in the long-term auctions) are then automatically included in the daily explicit auction under Use-It-Or-Sell-It (UIOSI) arrangements. This daily explicit auction takes place ahead of submission of bids into the DAS.

3.2.4 Forward

Under the current Greek market design, there is forward allocation of interconnection capacity. However, because of the presence of a gross mandatory pool on D-1, market participants can only sign financial contracts in relation to energy (eg. contracts for difference), as no (forward) bilateral contracts for physical delivery of electricity are allowed.

The interconnection capacity rights take the form of Physical Transmission Rights (PTRs). The long-term capacity auctions follow the “Pay-As-Cleared” principle, meaning that a single clearing price is set at the level of the marginal bid, which is the price that all market participants with higher bids will pay for their allocated capacity. Where the amount of capacity rights available in an auction is greater than the submitted bids, the clearing price is zero.

The only form of forward energy trading (if it could be considered as such) that has been observed in the Greek market is the pre-purchase of Capacity Adequacy Contracts (see Section 3.3 for more details). This was designed to provide a guarantee for future revenues, thus facilitating the financing of a generation project. In practice, this pre-purchase has been conducted once by DESMIE (former TSO) for a CCGT project.

3.2.5 Day Ahead

The day ahead market in Greece is a gross mandatory pool (the Pool) based around the Day Ahead Schedule (DAS), which produces the System Marginal Price (SMP), plant volumes and the interconnector flows for each hour of the following day (running from midnight to midnight Greek time).

The Market Operator operates the DAS, the goal of which is to meet demand for the next 24 hours by maximising social welfare subject to a number of constraints. These include technical constraints of the generating units and reserve requirements. Consequently, the ‘technical’ algorithm co-optimises the energy market and the reserve market simultaneously for all the hours of the day.

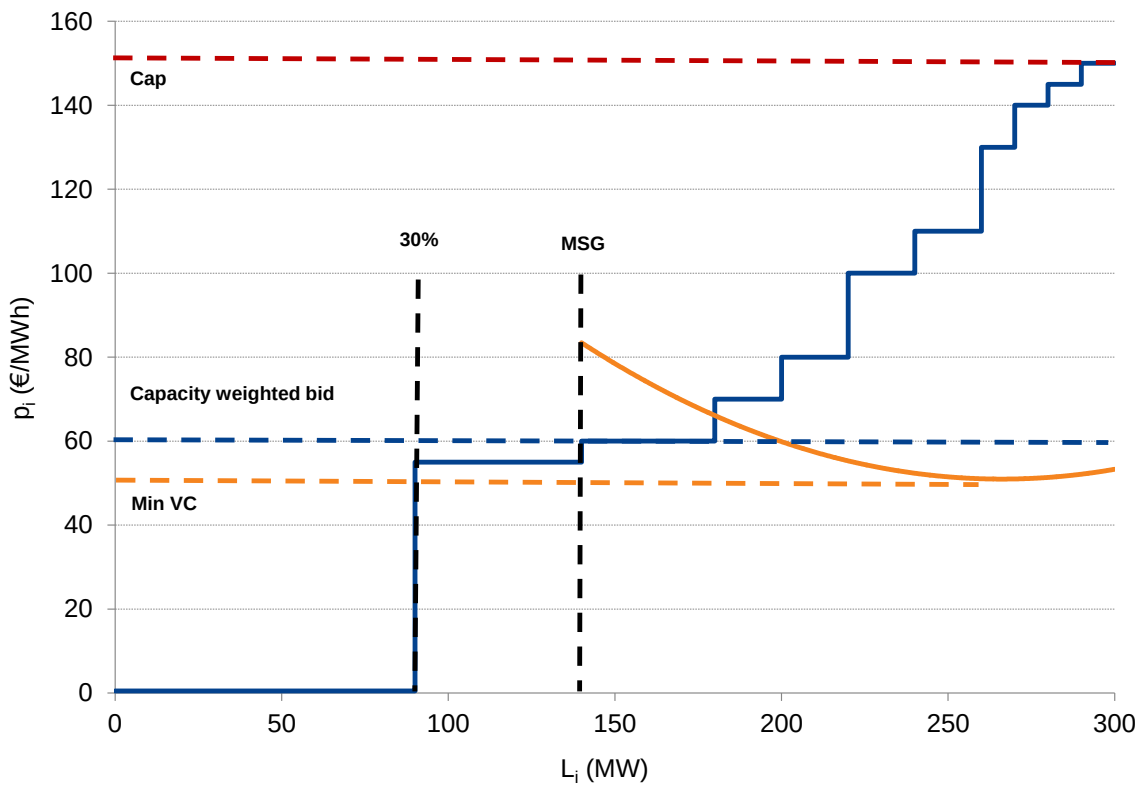
All generating units (other than mandatory hydro and renewable generation) submit the following information into the Pool:

- economic bids, which consist of a 10-step increasing function of prices and quantities for each one hour of the following day;
- bids for provision of primary and secondary reserve (which are broadly equivalent to frequency containment and frequency response reserves defined in the draft EB FG);
- generation costs, which are used to assess the validity of the economic bids; and
- technical parameters (e.g. start-up costs, shut-down costs etc).

The economic bids must respect the administratively set bid price floor and cap. The price cap is currently set to €150/MWh respectively. The price floor is set at zero for the

first bid step[38] and at the minimum variable cost of the generating unit for all subsequent bid steps. In addition, the capacity weighted average of all the bids of the unit has to exceed the same floor. Figure 14 shows an example of a valid bid structure from a thermal generating unit (with the solid orange line representing the variable cost at each level of production).

Figure 14 – Example of valid bid structure from a thermal generating unit



Specific rules are in place for bids from hydro generators (after having netted off mandatory hydro, which is treated as a must-run in the DAS). The bids are priced at a "water value" that is determined by RAE on a monthly basis. This value should reflect the saving of the variable cost associated with turning on a marginal thermal plant and account for hydro output restrictions.

Mandatory hydro (based on PPC's declarations) and renewable generation (based on the TSO's forecast) quantities are considered as must run and thus are included in the DAS without a price.

Suppliers and large electricity consumers submit similar offers to the economic bids provided by the generators (as a 10-step decreasing function). However, load offers are not priced (with the exception of exports and pumping).

Holding a physical transmission right (PTR) for interconnector capacity is a prerequisite for submitting an import or export offer into the DAS. Interconnector capacity holders who indicated an intention to use their long-term rights at 0700 on D-1 are responsible for

38 Which can refer to a quantity up to 30% of the net generation capacity of the unit.

ensuring that their bid into the DAS in relation to these rights is accepted (i.e. there is a scheduled flow for any capacity that they have said that they planned to use). This means that bids into the DAS in relation to these rights are priced very high or very low (i.e. zero for imports) so that they are sure to be accepted. Similarly, successful bidders in the daily explicit auction for interconnection capacity are then also responsible for ensuring that their bid into the DAS in relation to these rights is accepted.

3.2.6 Intraday

There is no intraday trading (or scheduling) in the current Greek market design as TSO dispatch is effectively the only activity taking place after the Pool. There is not even an opportunity to update the information used by the TSO for dispatch (which is based on the offers submitted at the day ahead stage for the use in the Pool).

3.2.7 Procurement of reserves

There are two steps in the procurement of primary and secondary reserve on D-1. Firstly, the DAS calculates the clearing price for the provision of balancing reserve (as opposed to balancing energy) based on the bids for reserve and the co-optimisation of reserve and energy in the Pool algorithm. There is a price cap of €10/MW for this clearing price. Tertiary reserve comes in the DAS with no price. However, the DAS determines only the clearing price for reserve and not which units will provide the reserve.

The TSO is responsible for the Dispatch Schedule that determines the actual dispatch instructions for the generating units, including which plants are used for reserve, with the aim of ensuring system security and reliability (at least cost). The (day ahead) Dispatch Schedule uses the same bids and costs submitted by generating units into the DAS, and the same algorithm as the DAS. However, the Dispatch Schedule can produce different dispatch patterns to the DAS as the DS is solved with updated plant availability and RES forecast and load forecast (instead of load declarations used in the DAS)

3.2.8 Activating balancing energy

The activation of balancing energy is done by the TSO through the dispatch process. This uses the bids and costs submitted into the Pool to respond to changes after the day-ahead stage, such as unexpected plant outages, or changes in wind and demand forecasts.

Under the current Greek market design, the ‘imbalance settlement’ process includes the clearing of transactions (for hourly settlement periods) with respect to:

- instructed energy deviations (i.e. the provision of balancing energy);
- uninstructed energy deviations (i.e. imbalances as defined under the Target Model);
- Ancillary Services; and
- Uplift Accounts.

Calculation of energy deviations is performed separately for every participant, with separate calculations for each load declaration, each generation unit and each interconnection trader. In every case a specific tolerance margin is taken into consideration when calculating the deviation between dispatched and metered quantities (i.e. if the metered volume is within the tolerance margin around the dispatch quantities, the metered volume shall be deemed to be equal to the dispatch quantity).

Any instructed increase in the generation of a unit when compared to the DAS (i.e. representing the provision of balancing energy) is paid at the System Imbalance Settlement Price (SIMP). Intermittent generation is deemed to be dispatched at its out-turn volume.

The SIMP is calculated after the event (i.e. ex-post) by solving the Pool algorithm considering out-turn data for demand, thermal generation availability, and renewable generation.

The SIMP is not applied to any instructed decrease in generation as the generator simply has to pay back the cost of generation (which may not equal its bid). This means that the infra-marginal rent is kept by the generator.

3.2.9 Imbalance Settlement

In the context of this report, Imbalance Settlement refers to the clearing of transactions with respect to **uninstructed energy deviations**. However, the Imbalance Settlement as per the current market arrangements is used for both compensation of instructed deviations and penalisation of uninstructed deviations (imbalances). Annex E discusses the Imbalance Settlement in more detail (through the use of examples) and describes our approach towards making a distinction between instructed and uninstructed deviations.

As described earlier, deviations are calculated on a unit basis (not a portfolio basis) for a settlement period of an hour (with a tolerance margin for deviations between dispatched quantities and metered volumes. The uninstructed energy deviation is calculated as the difference between the metered volume and the dispatch quantity. There is no deviation for intermittent generation as its dispatch quantity is set equal to the metered volumes.

Payments for uninstructed energy deviations are as follows:

- generator receives price of zero for all metered volumes above dispatched quantity; and
- generator pays SIMP for all metered volumes below dispatched quantity.

3.3 Additional features of the current Greek market design

We now discuss the cost recovery mechanism and the capacity adequacy mechanism. These are features of the existing Greek market design that do not fit easily into a particular building block but may raise questions in moving towards a market design that is compliant with the Target Model.

3.3.1 Capacity Adequacy Mechanism

The Grid and Market Operations Code in Greece provides for a capacity adequacy mechanism (CAM). The design of CAM is similar to that used in electricity markets in north-eastern USA, albeit adapted to the structure and characteristics of the Greek electricity market.

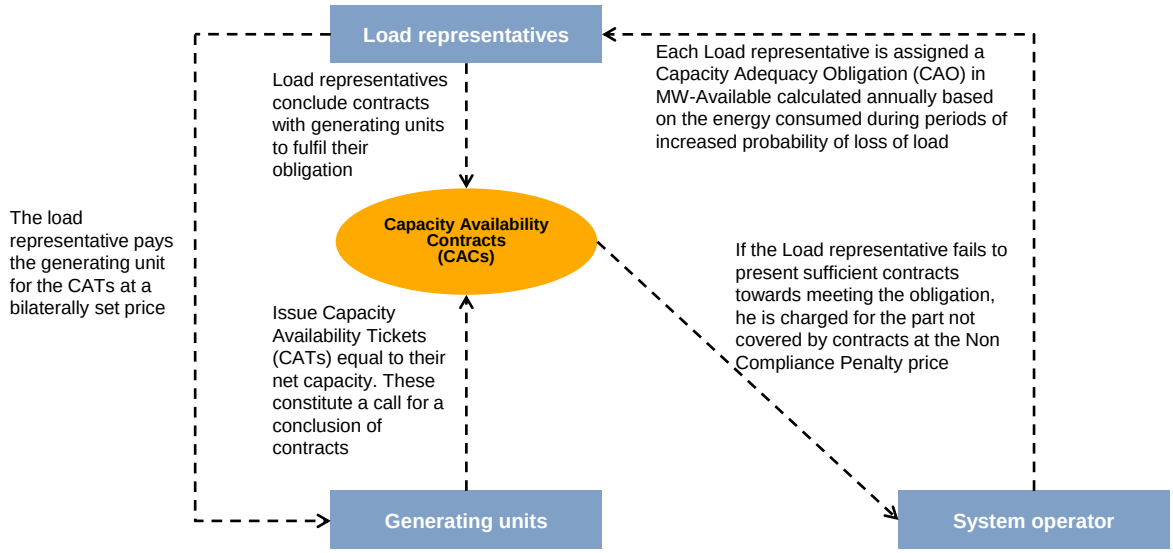
The CAM aims to ensure long-term capacity availability and to smooth wholesale electricity price fluctuations. This is designed to be done by guaranteeing part of the generators' fixed costs, hence reducing their business risk (a possible barrier to investment).

In theory, the CAM is based on a capacity obligation discharged by suppliers (or Load representatives), as described in Figure 15. A generator submits Capacity Availability

Tickets (CATs), each one corresponding to one MW of Available Capacity, to the CAT Registry, kept by ADMIE. The suppliers then purchase these CATs through Capacity Availability Contracts (CACs) in order to satisfy their Capacity Adequacy Obligation (CAO)[39]. The calculation of the CAO by ADMIE takes into consideration the required capacity reserve margin. This is determined annually by the Ministry of Energy, Environment and Climate Change, based on the regulator's opinion (following a recommendation by ADMIE).

A load representative is charged the Non Compliance Penalty for any part of its Obligation not covered by CACs. The Penalty value therefore defines the price cap for available capacity. It is set annually by RAE in the October before the Reliability Year (covering a calendar year), considering amongst other factors the capacity reserve margin and the cost of adding new generation capacity to the Greek electricity system. The Penalty value for 2012 is €45/kW.

Figure 15 – Schematic of the Capacity Adequacy Mechanism



However, to date, all market participants have participated in the CAM only through the Transitional Mechanism, which allows generators to conclude CACs with ADMIE rather than with suppliers. The Transitional Mechanism was initially intended to be used when capacity shortage was foreseen, but is now used for all available capacity.

Under the Transitional Mechanism, the TSO agrees contracts with the generators that can cover the capacity obligations placed on suppliers, who are required to make the payments to fund the contracts (at a regulatory set price equivalent to the Non-Compliance penalty value). All participating generators receive a proportion of this fund based on their availability.

3.3.2 Cost Recovery Mechanism

The 'technical' nature of the Day-Ahead Schedule (DAS) algorithm can potentially lead to situations where a unit committed in the DAS to generate (or gets called in the actual

39 Moreover the two counterparties are encouraged to sign, independently of the CAM, bilateral financial agreements in the form of Contracts for Differences (CfDs) or Call Options.

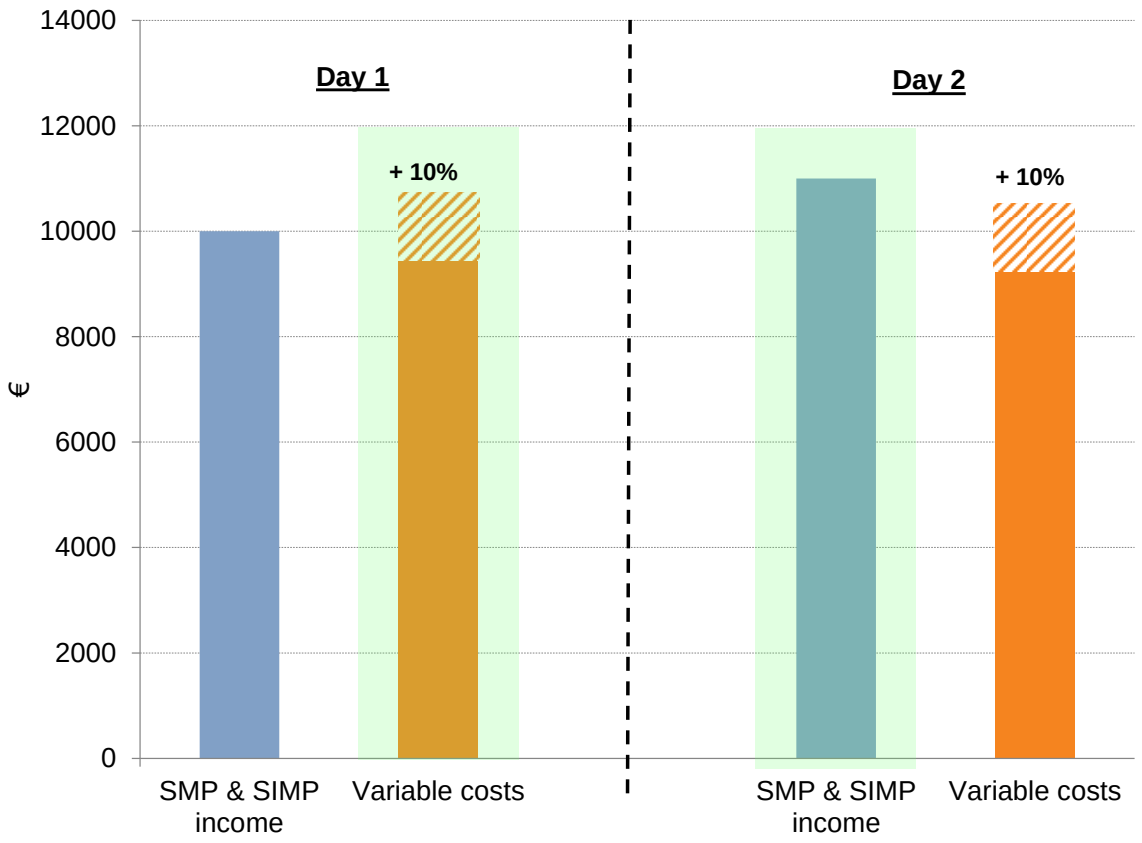
dispatch) is compensated with a payment lower than its actual bid, through the DAS and/or payments for balancing energy (or instructed imbalance). The Cost Recovery Mechanism was implemented to address such cases.

The Cost Recovery Mechanism ensures that all the units that are dispatched receive at least their variable costs and an additional premium (currently set at 10%) on a daily basis. The Cost Recovery Mechanism only considers the variable costs related to the minimum of dispatched quantities and metered volumes. It is based on the cost data submitted to the Pool, which is also used to assess the validity of bids into the Pool.

Figure 16 provides an example of the operation of the Cost Recovery Mechanism, in particular how the payments to a generating unit under this mechanism depend on their income from the DAS and for balancing energy.

On Day 1 the income is below 110% of the (applicable) variable costs of the unit. In this situation the cost recovery mechanism kicks in and the generating unit receives a top-up payment to ensure that its total revenue equals its variable costs plus 10%. On Day 2 the market income exceeds 110% of the generators' variable costs, and hence there is no payment to the generator under the cost recovery mechanism (but also no clawback of money from the generating unit, which keeps all of its market income).

Figure 16 – Cost recovery payments



3.4 Gap analysis

Table 8 uses our building block approach to summarise the main gaps that we have identified between the current design and the Target Model. This highlights that the substantive gaps are around the day ahead and intraday timeframes, in relation to

- the introduction of a Day Ahead Market (DAM) to implement price coupling in line with the Target Model; and
- introduction of an intraday market (IDM) and supporting trading platform.

This reflects major issues such as:

- ability of the TSO to influence dispatch decisions – which is much weaker at the day ahead stage under the Target Model than under the current Greek arrangements (e.g. reserve requirements are considered in Greek Pool algorithm but not in current proposals for Target Model algorithm);
- the extent to which Greek Day Ahead prices (based on technical solving algorithm with price caps and bid floors) are comparable to adjacent markets (many of which are not liquid or transparent);
- compatibility of a mandatory gross pool with the requirements for full day ahead price coupling under the Target Model; and
- the requirement under the Target Model for continuous intraday trading arrangements, when no opportunities for intraday rebidding exist in Greece at present.

On balancing, a key difference is that current Greek arrangements for procurement of balancing reserves and activation of balancing energy do not appear to facilitate the use of demand-side response. In addition, the activation of downwards balancing energy, which currently happens based on the merit order of the unit bids as per the DAS, is not subject to a marginal price (as there is a cost-based payment).

As the balancing rules are still under development, there remains uncertainty on the degree of harmonisation of products and procurement processes that will be required. Therefore, the extent of any gap between the Target Model and the current Greek arrangements on this aspect is not yet clear. However, we note that in principle, any material harmonisation of balancing arrangements will prove difficult to accommodate the co-optimisation of reserve and energy in the Greek market if that is not done in other markets.

On the settlement of uninstructed imbalances, there are two clear areas in which there is a gap between the current Greek arrangements and the Target Model:

- **length of settlement imbalance period** – 1 hour in Greece, maximum of 30 minutes under draft EB FG; and
- **pricing for (upwards) uninstructed imbalances** – zero in Greece, cost-reflective pricing under the Target Model.

For the first three building blocks (related to the availability of interconnector capacity), the gaps are primarily more around processes and timings rather than more substantive issues.

The Cost Recovery Mechanism and Capacity Adequacy Mechanism are not topics specifically addressed in the CACM NC, and hence are not included in Table 8. However, we note that because they could distort bids into the market coupling (by offering

additional revenue streams), they do not appear to be consistent at least with the spirit of the Target Model. In addition, the cost recovery mechanism allows for prices and costs to be submitted separately and used for different purposes, which can distort bidding incentives.

Table 8 – Gap analysis between Target Model and current Greek market design

Building block	Current Greek design	Target Model	Gap
Zoning	Sub-national generation prices possible but never implemented	Regular review of zone definition	Aligned in principle but need to comply with formal review process; Question mark about single demand price with zonal generation prices
(Interconnector) capacity calculation	NTC (although Flow Based has also been analysed by the Greek TSO)	NTC allowed but Flow Based preferred for 'meshed networks'	Uncertain as Flow Based not yet implemented in practice (and 'peninsula' status?)
Allocation of (interconnector) capacity between timeframes	Forward – annual, monthly (and daily) auctions No capacity held back for day-ahead or intraday	Approval role for NRAs, with scope to reserve capacity for balancing	Some capacity may need to be held back until at least the day-ahead timeframe
Forward	Explicit allocation of Physical Transmission Rights	Explicit allocation of physical or financial transmission rights using common platform	Move to common platform for transmission rights; allow forward energy trading, possibly cross-border only?
Day-ahead	Mandatory gross pool with 'technical' algorithm to determine SMP; co-optimisation of energy and reserve	Price coupling based on firm day-ahead prices and volumes;	Day-ahead bids, algorithm and timings not consistent with Target Model
Intraday	No Intraday trading (or opportunities for rebidding)	Continuous implicit trading with congestion pricing	No Intraday trading (or opportunities for rebidding for dispatch)
Procurement of balancing reserves	Co-optimisation of energy and reserve (primary, secondary and tertiary)	Harmonised products and procurement processes to facilitate sharing of reserves between TSOs	Participation of demand-side; Product definition and procurement through Pool?
Activation of balancing energy	Uses bids and costs for Pool; marginal (ex-post) price for increased production; cost-based (re)payment for reduced production	Harmonised products with marginal pricing and selection based on Merit Order	Participation of demand-side; Product definition and activation based on Pool inputs? Marginal pricing not used for reduced production
('Uninstructed') imbalance settlement	Generators receive zero price for upwards imbalance; pay marginal (ex-post) price for downwards imbalance; Hourly settlement period	Incentives for all parties to self-balance (day-ahead&real time); cost-reflective prices for all; Settlement period no more than 30 minutes	Zero price for upwards imbalance; Length of settlement period

3.4.1 Market design issues highlighted by RAE

In December 2011, RAE published a roadmap and action plan for the redesign of the Greek wholesale electricity market to comply with the Target Model. In general, the RAE view is that the current market design has managed to fulfil certain goals and progress has been made towards market opening with an additional 2GW of gas-fired generation having entered the market. However RAE identifies both structural and market design issues, some of which could prove to be obstacles towards complying with the Target Model.

Table 9 compares the findings of our gap analysis with RAE's conclusions on the compatibility of existing Greek market arrangements with the requirements of the Target Model. We have used the following classification:

- **certain incompatibility;** the proposed CACM rules would explicitly rule out the Greek market design feature, particularly in relation to coupling markets at the Day Ahead (DAM) and Intraday stages (IDM);
- **potential incompatibility;** the proposed CACM rules could be interpreted in a way that would rule out the Greek market design feature; and
- **difference to NWE markets;** there is nothing in the proposed CACM rules that would rule out the Greek market design feature but it may not be compatible with the spirit of the Target Model.

This table also includes the Capacity Adequacy Mechanism and the Cost Recovery Mechanism.

Table 9 – Comparison of RAE and Pöyry views on compatibility of existing Greek market design with Target Model

Greek market design feature	RAE view on compatibility	Pöyry view on compatibility
Explicit allocation of short-term (interconnector) rights	Certain incompatibility	Certain incompatibility
Lack of intraday market	Certain incompatibility	Certain incompatibility
Market operation timetable	Certain incompatibility	Certain incompatibility
Co-optimisation of energy and reserve markets	Certain incompatibility	Certain incompatibility for DAM and IDM
Technical market schedule algorithm	Potential incompatibility	Certain incompatibility for DAM and IDM
Market clearing issues	Potential incompatibility	Certain incompatibility for DAM and IDM)
Max and min bid prices	Potential incompatibility	Potential incompatibility
Cost recovery mechanism	Potential incompatibility	Difference to NWE markets (rather than Target Model rules)
Central dispatch/mandatory pool	Difference to NWE markets (rather than Target Model rules)	Difference to NWE markets (rather than Target Model rules)
Form of bids	Difference to NWE markets (rather than Target Model rules)	Potential incompatibility
No bilateral contracts	Difference to NWE markets (rather than Target Model rules)	Difference to NWE markets (rather than Target Model rules)
Imbalance Settlement	Difference to NWE markets (rather than Target Model rules)	Potential incompatibility
Capacity Adequacy Mechanism	Difference to NWE markets (rather than Target Model rules)	Difference to NWE markets (rather than Target Model rules)

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4. GAP ANALYSIS FOR ITALY AND SEE NORTHERN BORDERS

In this Chapter, we report the results of our analysis of the gaps between the Target Model requirements and existing electricity market design in Italy and in the SEE countries on the northern borders of Greece (Albania, FYROM, Bulgaria).

In general, the balancing markets and harmonization of balancing markets/resources are not developed in the SEE region. As a result, the Energy Community Secretariat issued a new study in the summer of 2012 to look into creating recommendations for a SEE Regional Balancing Market (BM). This study is expected to be completed in 2013. Given this, our gap analysis for SEE has considered procurement of balancing reserves together with the activation of balancing energy in a single step.

4.1 Summary

The target should be that all borders of Greece will participate in one common market coupling. However, in the first step it would be most likely that the Greece-Italian interconnection would participate in a price coupled mechanism while the others still will be based on explicit auctions. Other interconnections should then be added when they are ready. This reflects the fact that Italy is the market that is the closest to the Target Model, with substantial gaps for the other countries. Market redesign projects are under way in those countries, albeit at different stages of development.

Therefore, it is clear that for Greece, the easiest market coupling would be with Italy. This is based on the fact that Italy is the most mature market; it is close to being compliant with the EU Target Model and has system and already existing market coupling with others (Slovenia).

However, it will be important to not just focus on this border as the price coupling is based on a single algorithm, so that it will not be possible to participate in different price couplings on different borders. Therefore, the management of the interconnections to the SEE region and the creation of a robust trading framework on the northern borders will be important for Greece.

4.2 Gap analysis for Italy

Table 10 summarises the result of our gap analysis for Italy. It illustrates that Italy is in general close to being compliant with the EU Target Model as of today. It has a liquid day ahead wholesale electricity market, with zonal pricing, albeit for generation only. The GME, the market operator in Italy, is one of the participants in the PCR (Price Coupling of Regions), a project by the 6 biggest power exchanges in Europe developing a common price algorithm to be used as a single price coupling mechanism across Europe.

Italy has performed the major steps for to comply with the EU Target Model and has taken an active role in how to implement this going forward, for example in the PCR project. One possible major gap for Italy is whether the Target Model allows a single national wholesale electricity price for demand (the PUN price) when there are zonal wholesale electricity prices for generation.

Table 10 – Gap analysis between Target Model and current Italian market design

Building block	Current Italian design	Target model	Gap
Zoning	Italy is divided into 19 active zones (11 internal, 8 external)	Regular review of zone definition	Requirement to revise the zone definitions.
(Interconnector) capacity calculation	NTC	NTC allowed but Flow Based preferred for 'meshed networks'	Uncertain as Flow Based not yet implemented in practice (and 'peninsula' status?)
Allocation of (interconnector) capacity between timeframes	Forward – annual, monthly and daily (+intraday) auctions by CASC. No capacity specifically held back for day-ahead or intraday but made available to the DAM	Approval role for NRAs, with scope to reserve capacity for balancing	Varies per interconnection. The internal allocation is inline as well as the link between Italy and Slovenia. The CASC allocation process also consistent, but the daily auction should be through a price-coupled DAM/IDM.
Forward	Financial market through GME (MTE)	Explicit allocation of physical or financial transmission rights using common platform	Move to common platform
Day-ahead	Active and liquid DAM operated by GME (MGP). Two different market coupling methods; IT-SI is price coupled, the rest is based on explicit auctions by CASC	Price coupling based on firm day-ahead prices and volumes; no recognition of capacity mechanisms	Day-ahead prices ready for price coupling; GME is part of PCR project. The PUN price (weighted average price to consumers) is a Gap.
Intraday	Intraday market in GME (MI), run in 4 sessions where supplemental bids are allowed.	Continuous implicit trading with congestion pricing	Only local for Italy and not continuous. There are 2 auctions implemented on the northern borders.
Procurement of balancing reserves	Ancillary Services Market and Balancing Market (MSD/MB) operated by Terna	Harmonised products and procurement processes to facilitate sharing of reserves between TSOs	Product definition; Local, but the products are in line with other developed markets in Europe.
Activation of balancing energy	Balancing Market (MB) operated by Terna	Harmonised products with marginal pricing and selection based on Merit Order	Using merit order, but not harmonised with all neighbours. Pay-as-bid, not marginal pricing
('Uninstructed') imbalance settlement	Imbalance settlement	Incentives for all parties to self-balance (day-ahead&real time); cost-reflective prices for all: Settlement period no more than 30 minutes	None

4.3 Gap analysis for the SEE Region

The SEE region is seeking to create a common action plan for the creation of a regional solution for the development of its energy markets through the Energy Community. As part of our study on SEE Wholesale Market Opening (SEE WMO)[40] for the Energy Community (and funded by the World Bank), we developed a proposal for regional as well as local action plans. After the acceptance of this study, the Energy Community Regulatory Board (ECRB) has developed a regional action plan[41] based on this together with ENTSO-E. This plan has been approved by the Ministerial Council of the Energy Community and thereby this plan is binding for all parties. This plan will be monitored by EC as well as the regional group for SEE in ENTSO-E as well as ACER.

40 SEE Wholesale Market Opening. Final report – updated with Ukraine and Moldova', Poyry Management Consulting and Nord Pool Consulting AS, December 2011.

41 'Regional Action Plan for Market Integration in South East Europe', ENTSO-E and ECRB.

In general, the countries of the SEE region have major work to do before being in compliance with the Target Model. To acknowledge this, this region has been granted a one year extension to 2015 for compliance.

The analysis for the SEE countries presented in Table 11 (and in the subsequent sections) is based on the work we carried out in our SEE WMO study. However, the analysis has been adapted to follow the building blocks we have used to describe the Target Model and the existing Greek market design (as opposed to the format used in the SEE WMO study). We have also updated the analysis where appropriate to reflect recent developments in the region.

Table 11 – Summary for SEE region of gap analysis between Target Model and today's market design

Building block	Current SEE design	Target model	Gap
Zoning	Not covered	Regular review of zone definition	Need to comply with formal review process, however as the countries in general are so small it is not relevant for most countries to have internal zones (exception Ukraine)
(Interconnector) capacity calculation	NTC	NTC allowed but Flow Based preferred for 'meshed networks'	Uncertain as Flow Based not yet implemented in practice, but the CAO is investigating Flow Based methods*
Allocation of (interconnector) capacity between timeframes	Forward – annual, monthly (and daily) auctions No capacity held back for day-ahead or intraday	Approval role for NRAs, with scope to reserve capacity for balancing	Not coordinated at the moment, the SEE CAO* might improve the coordination but is still just a step towards market integration.
Forward	Explicit allocation of physical transmission rights	Explicit allocation of physical or financial transmission rights using common platform	Move to common platform; allow forward energy trading?
Day-ahead	Various market designs per country, no DAM implemented. Commitment through EC to create regional solution	Price coupling based on firm day-ahead prices and volumes;	Large at the moment; Day-ahead prices not comparable with other markets (and hence not suitable for implicit auctions)
Intraday	No intraday trading	Continuous implicit trading with congestion pricing	Large; Intraday trading of interconnector capacity required under existing congestion management guidelines
Procurement and activation of balancing	Various options implemented, not coordinated	Sharing of resources across TSOs through harmonised products, procurement processes and pricing structures	There is very limited harmonisation of products in the region; Participation of demand-side is in general missing. A new SEE Regional BM study has been launched in 2012 to be delivered next year that will investigate and deliver recommendations for this in the whole region.
Imbalance settlement	Various options, but balancing markets is missing	Incentives for all parties to self-balance (day-ahead&real time); cost-reflective prices for all; Settlement period no more than 30 minutes	Requirements for self-balancing, particularly for 'renewable' generation

* Bulgaria and Serbia are not participating in the SEE CAO

4.4 Gap analysis for Albania

Albania is one of the countries in the SEE region that has made major steps in its preparation for a regional market from a starting point where it was well behind the other

parties. Even though there still are many improvements that are required to comply with the EU regulations (as summarised in Table 12), Albania has proved its willingness to move forward. The privatisation of their distribution company as well as the introduction of foreign investment on the generation side is expected to drive changes forward.

Table 12 – Gap analysis between Target Model and today's market design for Albania

Building block	Current design in Albania	Target model	Gap
Zoning	Not covered	Regular review of zone definition	Need to comply with formal review process, however Albania is small it is not relevant to split in more than one zone.
(Interconnector) capacity calculation	NTC	NTC allowed but Flow Based preferred for 'meshed networks'	Uncertain as Flow Based not yet implemented in practice. Albania will participate in CAO, who is investigating Flow Based methods .
Allocation of (interconnector) capacity between timeframes	Forward –monthly and daily auctions No capacity held back for day-ahead or intraday	Approval role for NRAs, with scope to reserve capacity for balancing	Not coordinated at the moment, CAO might improve the coordination but is still just a step towards market integration.
Forward	Explicit allocation of physical transmission rights	Explicit allocation of physical or financial transmission rights using common platform	Move to common platform; allow forward energy trading?
Day-ahead	No DAM implemented, KESH stands for 99% of generation and are obliged to supply based on regulated tariffs	Price coupling based on firm day-ahead prices and volumes;	Large but improving; Day-ahead prices not comparable with other markets (and hence not suitable for implicit auctions) ; however, the distribution has been sold to CEZ; Statkraft has bought a large HPP.
Intraday	No intraday trading	Continuous implicit trading with congestion pricing	Large at the moment; Intraday trading of interconnector capacity required under existing congestion management guidelines
Procurement and activation of balancing	Bilateral procurement with KESH, not market solution. National solution	Sharing of resources across TSOs through harmonised products, procurement processes and pricing structures	SEE regional balancing study has recently been launched
Imbalance settlement	TSO is responsible for the imbalance settlements process	Incentives for all parties to self-balance (day-ahead&real time); cost-reflective prices for all; Settlement period no more than 30 minutes	Requirements for self-balancing, particularly for 'renewable' generation

4.5 Gap analysis for FYROM

A new Energy Law has been adopted in FYROM (Former Yugoslavian Republic of Macedonia) and came into effect on February 2011. This Law constitutes a major step forward in the necessary energy reforms in the country.

The new Law set the scope of obligations and strict deadlines for the development of secondary legislation as a precondition for further market opening. Significant efforts are being undertaken by both relevant institutions, ERC and the Ministry of Economy, to comply with the timeframes stipulated in the Law.

These changes cannot yet be seen in the gap analysis shown in Table 13, as the effect has not created any changes yet. However, the improvement of the legal framework is expected to create some changes in the near future.

Table 13 – Gap analysis between Target Model and today's market design for FYROM

Building block	Current FYROM design	Target model	Gap
Zoning	Not covered	Regular review of zone definition	Need to comply with formal review process, however as FYROM is so small it is not relevant to split in more than one zone.
(Interconnector) capacity calculation	NTC	NTC allowed but Flow Based preferred for 'meshed networks'	Uncertain as Flow Based not yet implemented in practice, but also part of CAO, who is investigating Flow Based methods
Allocation of (interconnector) capacity between timeframes	Forward – annual, monthly and daily auctions No capacity held back for day-ahead or intraday	Approval role for NRAs, with scope to reserve capacity for balancing	Not coordinated at the moment, CAO might improve the coordination but is still just a step towards market integration.
Forward	Explicit allocation of physical transmission rights	Explicit allocation of physical or financial transmission rights using common platform	Move to common platform; allow forward energy trading?
Day-ahead	No DAM implemented; Full supply contract between generator (ELEM) and distributor (EVN). EVN, as a supplier, can purchase from others if terms more favourable than from the regulated generator	Price coupling based on firm day-ahead prices and volumes	Day-ahead prices not comparable with other markets (and hence not suitable for implicit auctions); Not as much restructuring as in Albania
Intraday	No intraday trading	Continuous implicit trading with congestion pricing	Large at the moment; Intraday trading of interconnector capacity required under existing congestion management guidelines
Procurement and activation of balancing	Bilateral procurement, not market solution. National solution	Sharing of resources across TSOs through harmonised products, procurement processes and pricing structures	SEE regional balancing study has recently been launched
Imbalance settlement	Balancing mechanism under establishment.	Incentives for all parties to self-balance (day-ahead&real time); cost-reflective prices for all; Settlement period no more than 30 minutes	Requirements for self-balancing, particularly for 'renewable' generation

4.6 Gap analysis for Bulgaria

The provisions of the CACM NC will apply directly in Bulgaria as a EU member state. There have been some steps in improving the market framework in Bulgaria but it is hard to see any real effect of this as of this point in time as shown in Table 14. However, there is a large market design project that will start in 2012 that hopefully will start the implementation of a Bulgarian energy market compliant with the EU Target Model.

Table 14 – Gap analysis between Target Model and today's market design for Bulgaria

Building block	Current design in Bulgaria	Target model	Gap
Zoning	Not covered	Regular review of zone definition	Need to comply with formal review process, but Bulgaria does not have any major internal bottlenecks today.
(Interconnector) capacity calculation	ATC	NTC allowed but Flow Based preferred for 'meshed networks'	Uncertain as Flow Based not yet implemented in practice
Allocation of (interconnector) capacity between timeframes	Forward – annual, monthly and weekly auctions No capacity held back for day-ahead or intraday	Approval role for NRAs, with scope to reserve capacity for balancing	Separate auctions on each border, not interested in participating in SEE CAO.
Forward	Explicit allocation of physical transmission rights	Explicit allocation of physical or financial transmission rights using common platform	Move to common platform; allow forward energy trading?
Day-ahead	No DAM implemented, but there has been started a project on market development	Price coupling based on firm day-ahead prices and volumes;	Large at the moment; Day-ahead prices not comparable with other markets (and hence not suitable for implicit auctions) ;
Intraday	No intraday trading	Continuous implicit trading with congestion pricing	Large at the moment; Intraday trading of interconnector capacity required under existing congestion management guidelines
Procurement and activation of balancing	National solution established	Sharing of resources across TSOs through harmonised products, procurement processes and pricing structures	SEE regional balancing study has recently been launched
Imbalance settlement	Balance mechanism, metering and settlement established	Incentives for all parties to self-balance (day-ahead&real time); cost-reflective prices for all; Settlement period no more than 30 minutes	Requirements for self-balancing, particularly for 'renewable' generation

5. POSSIBLE COMPLIANCE OPTIONS FOR THE GREEK MARKET

We have investigated three different high-level options for Greece to comply with the requirements of the Target Model. Those are:

- adaptation of the current Greek model ('Adaptation option');
- a North West European power exchange model ('NWE option'); and
- a hybrid option of a voluntary pool and bilateral markets ('Hybrid option').

The above options are designed to be compliant (subject to detailed legal interpretation) with the requirements of the (draft) Framework Guidelines, which are expected to be embodied in the relevant Network Codes. However, full and detailed legal review of the final Network Codes (when they become available) may be needed to establish a more definitive view on compliance.

5.1 Overview of options

As discussed earlier we have defined nine building blocks to form the basis of our description of different electricity market designs, and for our analysis of the gap between the Greek market and the European Target Model (see Section 3.4). Table 15 summarises the three options that we have developed for the Greek market to comply with the requirements of the Electricity Target Model. The text in bold highlights the key differences between the options.

Table 15 – Summary of options for compliance with Target Model

Building block	Adaptation option	NWE option	Hybrid option
Zone definition	To be assessed every two years with scope for review	To be assessed every two years with scope for review	To be assessed every two years with scope for review
Capacity calculation methodology	Flow Based (unless meet criteria for retaining NTC)	Flow Based (unless meet criteria for retaining NTC)	Flow Based (unless meet criteria for retaining NTC)
Allocation of capacity between timeframes	NRA approval	NRA approval	NRA approval
Forward	Common European platform for (re)trading of long-term interconnector rights; Physical interconnector rights **(Physical) forward energy trading through existing Greek Pool (run earlier on D-1, before DAM)**	Common European platform for (re)trading of long-term interconnector rights; Physical interconnector rights **Physical (and financial) bilateral trading of energy**	Common European platform for (re)trading of long-term interconnector rights; Physical interconnector rights **Physical (and financial) bilateral trading of energy**
Day-ahead	**(Limited) adjustment volumes** in price coupling through DAM **(power exchange)**	Price coupling through DAM **(power exchange)**	Price coupling through DAM **(through which all previously uncontracted volumes must be traded)**
Intraday	(Limited) adjustment volumes in price coupling through IDM (continuous trading)	(Limited) adjustment volumes in price coupling through IDM (continuous trading)	(Limited) adjustment volumes in price coupling through IDM (continuous trading)
Procuring balancing reserves	**Co-optimisation in Pool**	**Separate ancillary service market(s)**	**Separate ancillary service market(s)**
Activating balancing energy	Marginal pricing **with activation based on Pool**	Marginal pricing; **Separate balancing mechanism**	Marginal pricing; **Separate balancing mechanism**
Imbalance settlement	30 minute settlement period; Cost-reflective pricing **based on ex-post Pool** (and accounting for market coupling results)	30 minute settlement period; Cost-reflective pricing **based on actual balancing costs**	30 minute settlement period; Cost-reflective pricing **based on actual balancing costs**

5.1.1 Common features

In presenting the options detailed in this Chapter, we have considered only six relevant building blocks. We have not considered variations in the remaining three building blocks (all related to how much interconnector capacity is available for allocation):

- zone definition;
- capacity calculation; and
- allocation of capacity between timeframes.

This is because in these areas, the CACM FG and draft CACM NC generally set out requirements for processes to be in place (e.g. around regulatory review and approval) rather than particular market design features. Therefore, compliance with the Target Model requires these processes to be put in place rather than necessarily a change to market design. These processes will in turn require a further set of decisions to be taken (e.g. periodic assessment of market zoning), which is beyond the scope of our current project (particularly given the need for supporting detailed quantitative analysis).

These three building blocks are discussed briefly below.

5.1.1.1 Zone definition

A formal process for a regional review of zone definition on a two-yearly basis must be put in place in line with the proposed provisions in the CACM NC (Articles 39-43 of the July 2012 draft), consistent with the principles set out in Section 2 of the CACM FG.

An example of this type of review is the study of existing price zones launched in July 2012[42] by the TSOs and the NRAs in the Central West Europe (CWE) region, covering Germany, France, Belgium, the Netherlands and Luxembourg.

In Section 3.2.1, we described how there is a zonal price provision in the existing Greek market design. Our understanding is that retaining a single national wholesale electricity price for demand (as would be done under the current zonal provision in the Greek market design) whilst moving to zonal wholesale electricity prices could not be consistent with the Target Model. If the intention of the provision in the current Greek design is to maintain a single national **retail** electricity price, then other measures may be available to offset regional differences in the wholesale electricity price.

However, there has not been a formal review of the zone definition in the Greek market in line with the specific criteria set out in the draft CACM NC. Therefore, it is quite possible that the Greek market will remain a single zone even after the implementation of the Target Model.

However, Italy currently has zonal wholesale prices for generation but a single national wholesale price for demand. We are not aware of any proposals to change Italian zoning arrangements to comply with the proposed requirements of the CACM NC.

5.1.1.2 Capacity calculation

It is not obvious that there is any change required to the current Greek arrangements on this area, particularly as the Flow Based capacity calculation methodology has not yet been implemented in practice In addition, it is unclear as to whether or not Greece would fall under the category of a peninsula, which would allow it to retain the NTC methodology. In any case, the Greek TSO has already started carrying out analysis of the application of Flow Based methodology to Greek interconnectors.

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42 'Study of existing cases and preparation of the qualitative analysis', CWE Price Zone Study Taskforce, July 2012.

One area that will be of interest to Greece is the treatment of losses on the interconnector with Italy. The July 2012 draft of the CACM NC allows for, but does not mandate, losses to be considered in interconnector capacity calculation and in the algorithm (Articles 2, 30 and 48).

Our understanding is that the settlement processes in Greece currently take into account losses. However, in practice, interconnector losses may not directly affect the results of the Pool, as interconnector bids are designed to ensure flows in line with nominations (although presumably losses are taken into account by parties when making these nominations).

5.1.1.3 Allocation of capacity between timeframes

The CACM FG require NRAs to review and approve the volume of annual capacity rights as well as the principles for allocating capacity between timeframes. Therefore, this process needs to be in place to ensure compliance, but there is no particular requirement (in the July 2012 draft NC) on what the principles should be.

In addition, the draft version of the EB FG[43] allows for reservation of interconnector capacity for balancing purposes subject to a positive CBA. Our understanding is that there is no such reservation at present on the Greek interconnectors, and that in general, any such reservation may be much more likely on DC interconnectors than AC ones – for example, some capacity is being held back for balancing on the new subsea interconnector being developed between Norway and Denmark.

5.1.2 Areas of differentiation between the options

We now consider in turn the major areas of differentiation between the options for the six remaining building blocks.

5.1.2.1 Forward

The options for (physical) trading of energy in the forward timescale are one of the key areas of differentiation between our options. It has significant impacts on the relative importance of the DAM and IDM.

Under the Target Model, forward trading of energy provides an opportunity for nomination of physical interconnector flows against physical transmission rights. Such nomination is not possible from the DAM onwards, as price coupling determines the residual flows from that point onwards (subject to the provisions for transitional arrangements for explicit intraday interconnector access set out in Articles 91 to 95 of the July 2012 draft of the CACM NC).

In our Adaptation option, the existing gross mandatory pool (the Pool) is run before the DAM used for the day-ahead price coupling. Consequently, the DAM and IDM are used as adjustment markets, designed to take account of changes after the Pool is run.

In the NWE market and in the hybrid option, the DAM in particular is associated with much higher trading volumes, with the intraday market acting as the major adjustment market.

In all three options, we assume that the long-term interconnector rights remain physical.

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43 Article 4.3 in 'Framework Guidelines on Electricity Balancing. Draft for consultation. DFGEB-2012-E-004,' ACER, 24 April 2012.

5.1.2.2 Day-ahead

In all three options, a DAM is used to implement price coupling in Greece. Therefore, all of the options have a common set of timings and processes, and a set of bid formats that are expected to comply with the algorithm being developed under the PCR project.

In the Adaptation and NWE options, the DAM is assumed to take the form of a power exchange as typically seen in Western Europe, with features such as:

- Use of (different) types of block bids to overcome some of the non-convexities typically associated with generation that cannot easily be reflected in a simple bid – such as start-up and shut-down costs, ramp rates etc.
- Participation is (typically) entirely voluntary (although there is scope for specific market maker arrangements).

In the Hybrid option, a pool is used which differs from the power exchange model in the following aspects:

- Use of more complex bid formats (minimum income condition bids etc) to overcome some of the non-convexities associated with generation and demand.
- Forward bilateral trades are possible but participation in the DAM is compulsory for any volumes not subject to bilateral contracts by the Day-ahead stage (i.e. no physical withholding of capacity).
- The DAM has information on all contracted volumes (including bilateral volumes).

5.1.2.3 Intraday

All three options are similar in their use of continuous intraday trading. We note that the existing voluntary pool markets (Spain and Italy) use periodic intraday auctions rather than continuous trading. However, we expect that in order to comply with the Target Model, these markets will need to introduce some form of continuous trading (even if the periodic auctions are kept as a supplementary measure).

5.1.2.4 Procuring balancing reserves

As the balancing rules are still under development, there remains uncertainty on the degree of harmonisation of products and procurement processes that will be required. In addition, it is unclear how strong the requirement will be to facilitate the use of demand-side resources for balancing. Therefore, we differentiate our options in relation to the strength of harmonisation of procurement (and activation) of balancing resources.

In the Adaptation option, we retain the procurement of balancing reserves through the co-optimisation carried out in the gross mandatory pool. In the NWE and hybrid options, there are new specific ancillary services markets for the procurement of reserves.

5.1.2.5 Activating balancing energy

Similarly, the bids used in the gross mandatory Pool in the Adaptation option are also used for the activation of balancing energy (through the dispatch process). There remains a question of whether any intraday rebidding would be taken into account in the activation of balancing energy.

In the NWE and Hybrid options, balancing energy is activated through a balancing mechanism (operated by the TSO) that is separate to the wholesale market (operated by the NEMO).

5.1.2.6 Imbalance settlement

The Adaptation option retains the use of the Pool processes for balancing services through co-optimisation with energy, whereas balancing and wholesale markets are effectively separate in the NWE and Hybrid options.

This has implications for the settlement of imbalance arrangements, and in particular for the calculation of costs used to set the (uninstructed) imbalance price. In the Adaptation option, the current Greek arrangements are retained with the SIMP however used both for settling downwards and upwards uninstructed imbalance. The SIMP is based on an ex-post optimisation of the Pool algorithm (taking into account out-turn data for demand, intermittent generation and plant availability). This reflects an 'optimised' balancing cost, which should reflect just the (optimised) cost that would have been incurred in dealing with energy imbalances (as the same network constraints are considered in the algorithm used in the DAS and in the SIMP calculation).

In the NWE and Hybrid options, the imbalance prices are based on actual costs incurred by the TSO in responding to energy imbalances. However, the challenge is excluding costs incurred in managing network constraints – these should not be reflected in the price applied to energy imbalances, but the TSO may take actions in the balancing mechanism that address energy imbalances and/or network constraints. Therefore, it is not straightforward (or even possible) to definitively isolate the costs of dealing with energy imbalances from general balancing actions taken by the TSO.

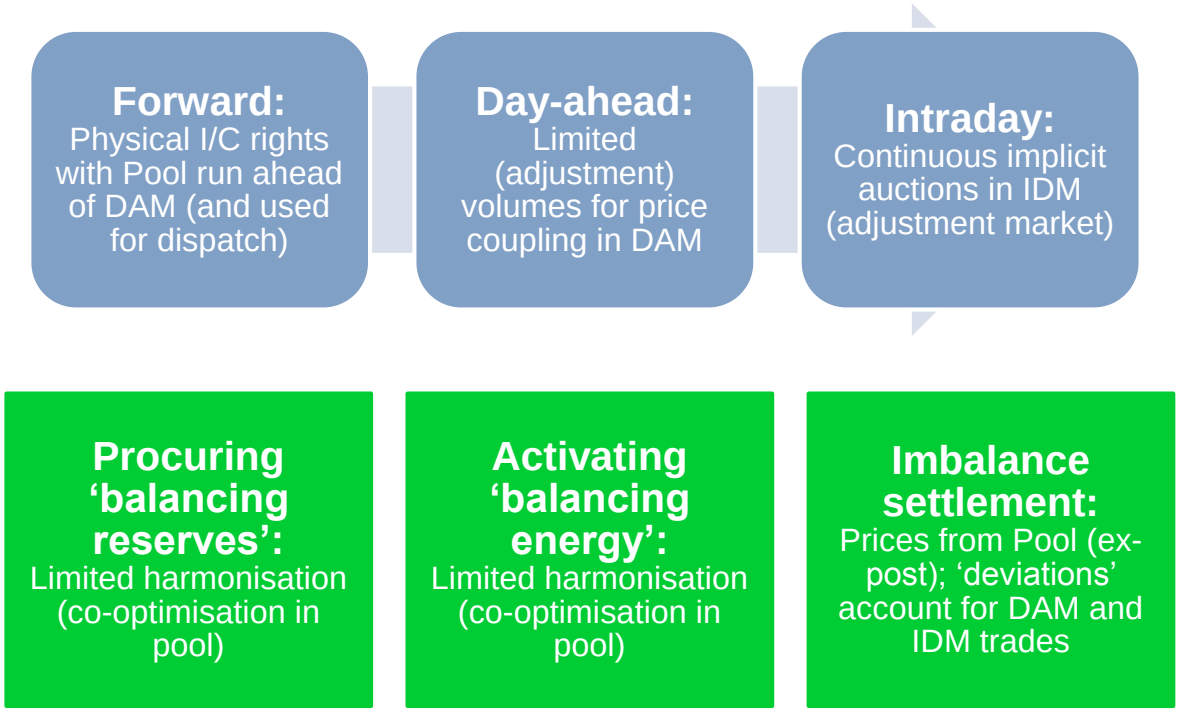
5.2 Adaptation of the current Greek model ('Adaptation option')

This option is intended to achieve compliance (subject to detailed legal interpretation) whilst carrying out minimum change. This is intended to ensure that market participants would not have to completely change the way they participate in the market when compared to the current situation, and the TSO and Market Operator could broadly have the same responsibilities as now.

Figure 17 details the structure of the Adaptation option under the six relevant building blocks. In this option, we assume that many of the existing features of the Greek market would remain intact (if moved forward in time) with compliance being achieved by the gross mandatory pool becoming a 'forward' rather than a Day Ahead market. This could allow the market to maintain the form of a gross mandatory pool with central dispatch.

In the subsequent sections (Sections 5.2.1 to 5.2.6), we look in more detail at the issues for each building block, including in relation to implementation and Target Model compliance.

Figure 17 – Building block summary of the Adaptation option



Both the Capacity Adequacy Mechanism (CAM) and the Cost Recovery Mechanism **could** remain in place within the context of the Pool. The Target Model does not explicitly rule out the use of additional mechanisms, such as the Cost Recovery Mechanism and the Capacity Adequacy Mechanism. However, we note that the impact of this on bids and offers in the Greek market may distort the relative level of these bids compared to those in other markets.

5.2.1 Forward

There are two key aspects to forward trading – interconnector capacity and energy.

With respect to the interconnector capacity, the minimum changes are primarily process-related as the explicit allocation of physical transmission rights is specifically allowed under Section 4.1 of the CACM FG. The key minimum change will be that (re)trading of long-term capacity rights must occur on a common European platform (although in practice regional platforms may be developed as an interim step).

Under this option, we do not propose the introduction of a bilateral 'forward' market for energy as observed in NWE countries (although this would be an additional possibility, using financial products). Instead, we propose to run the existing Pool on D-1 but shortly before the DAM, so that it would effectively constitute a forward market (under the strict definition of forward being all trading before the DAM).

In principle, the arrangements for the Pool would remain largely as they are today with the generating units submitting the same information as now (same bid format, technical characteristics etc.), and export/import offers being limited to holders of interconnector capacity. Participation in the Pool would remain mandatory, the algorithm would continue to co-optimise energy and reserve, and the resulting schedule would be **firm**.

We do not expect the retention of the daily explicit auction of interconnector capacity (on borders where price coupling has been introduced) in this option given the issues around timing and compliance. Given the timings for the Pool may shift forward, there may be insufficient time to collect the nominations from long-term interconnector capacity holders and then process the explicit (short-term) auctions before the running of the Pool. We would expect compliance issues with the retention of the short-term explicit auctions because it seems to conflict strongly with the spirit of the Target Model (based around implicit interconnector capacity auctions from the day ahead stage onwards). Our understanding is in line with RAE's description of the explicit allocation of short-term (interconnector) rights as being incompatible with the Target Model.

This leads onto one of the key issues as to whether our Adaptation option would be deemed to be compliant with the CACM NC (once they are finalised). This is to the extent where using the DAM as an adjustment market would be compliant, given that the mandatory Pool is still run on D-1 which may mean that there are very few volumes (if any) being traded through the DAM.

5.2.2 Day Ahead

In order to comply with the Target Model, a Day Ahead Market (DAM) has to be implemented to allow all available interconnection capacity to be allocated through a single price coupling algorithm (across Europe) based on the marginal pricing principle. The market coupling algorithm will have to be in line with the methodology adopted for the European price coupling and all the solving algorithms of the surrounding countries (which are included in the price coupling). For example, the Target Model currently has no requirement (or even expectation) for the algorithm to allow the co-optimisation of energy and reserve. In this option, we have assumed that the DAM operates in line with the power exchanges of North West Europe in terms of:

- Use of (different) types of block bids(as described in Annex C.1) to overcome some of the non-convexities associated with generation and demand – such as start-up and shut-down costs, ramp rates etc.
- Participation is (typically) entirely **voluntary** (although there is scope for specific market maker arrangements).

The DAM will need to comply with the key timings set out for the DAM in the July 2012 draft of the CACM NC:

- available interconnector capacities to be published by 1100 Market Time[44] (1200 Greek time) on D-1 (Article 56);
- gate closure is proposed to be at 1200 Market Time (1300 Greek time) on D-1 (Article 57); and
- scheduled interconnector flows in the DAM are to be notified to TSOs by 1530 Market Time on D-1 (1630 Greek time), alongside the publication of market information (Article 61).

[44] The July 2012 draft CACM NC defines **Market Time** as *"Central European Summer Time or Central European Time, whichever is in effect. In essence, it is the local time in Brussels".*

5.2.3 Intraday

Even under the minimum change envisaged for the Adaptation option, there would need to be the introduction of an Intraday Market (IDM) that allows continuous intraday trading with pricing of congestion.

The IDM would also need to comply with the process requirements described in Section 2.3.6 of this report, such as:

- Cross Zonal Capacity and Allocation Constraints to be provided to the Market Coupling Operator no later than 15 minutes prior to Intraday Cross Zonal Gate Opening Time (Article 66 of the July 2012 draft CACM NC);
- a harmonised gate closure time, which is proposed to be a maximum of one hour prior to the start of the relevant time period (Article 67 of the July 2012 draft CACM NC); and
- a shared order book and capacity management module.

In the Adaptation option, we do not propose the introduction of periodic intraday auctions to complement the continuous trading as this would represent further change.

5.2.4 Procuring balancing reserves

The European rules on balancing are at a much earlier stage than for CACM, with ACER not having to submit the EB FG to the EC for approval until September 2012 . This means that there remains uncertainty on the degree of harmonisation required in the procurement of balancing services. As a result, we have considered the minimum changes to the current Greek market design under this Adaptation option. As the European rules become more detailed, it will become clearer whether or not further change is required to ensure compliance with the Target Model.

Therefore, we assume that the current procurement processes for reserves remain in place – co-optimisation of energy and reserve in the Pool (including both the forward, ex-DAS, and the Dispatch Schedule) for primary, secondary and tertiary reserve.

The use of the Pool may allow only limited harmonisation of the procurement of balancing reserves with other countries, particularly if they have separate balancing markets (from their energy markets). Therefore, the stronger the requirement for harmonisation, the greater the challenge for retaining reserve procurement through the Pool.

In addition, there may be question marks about whether the Pool sufficiently facilitates the participation of demand-side in providing balancing reserves. This is an issue of interpretation at this stage, with specific requirements of the Target Model on this not being developed until the drafting of the Balancing NCs (between October 2012 and October 2013).

5.2.5 Activating balancing energy

We assume that as at present, the TSO activates balancing energy based on the inputs into the Pool. Given this, we have identified one minimum change for this building block, which is the use of a marginal price (as opposed to a cost-based payment) for activation of downwards balancing energy.

The simplest approach may be to use the SIMP (i.e. to be repaid by generators), as is used for upwards balancing energy. This means that generating units that are instructed to reduce their output would be paying back the SIMP rather than the cost as per the

current market arrangements. However, this could expose some generators to risk in the circumstances that for some reason, they are dispatched downwards but the SIMP is higher than the SMP.

The impact of this may be mitigated by the provisions of the Cost Recovery Mechanism. Through that the generator would not be out of pocket. However, as noted earlier, the Cost Recovery Mechanism may not be an enduring feature of the Greek market. Therefore, if the Adaptation option is taken forward into a detailed design phase, it merits consideration as to whether specific compensation arrangements should be in place for these circumstances (and whether this will then be compliant with the Target Model). For example, the likelihood of such circumstances could be explored as part of the detailed design phase.

We also note that using the Pool inputs to activate balancing energy may allow only limited harmonisation with other countries, particularly if they have separate balancing markets and allow intraday rebidding. Similarly, there may be question marks about whether the use of the Pool inputs sufficiently facilitates the participation of demand-side in providing balancing energy.

5.2.6 Imbalance settlement

In the context of this report, Imbalance Settlement refers to the clearing of transactions with respect to **uninstructed energy deviations**. We have identified two minimum changes in this building block:

- in line with the requirements of the draft EB FG, the imbalance settlement period will be (no longer than) 30 minutes; and
- there is also the use of cost-reflective pricing for upwards uninstructed imbalances (currently zero) as well as for downwards uninstructed imbalances.

The simplest approach for the pricing of upwards uninstructed imbalances may be to use the SIMP, as is used for settling downwards uninstructed imbalances.

Section 1.3 of the draft EB FG defines imbalances as deviations between metered volumes and market deals (covering energy and reserve). This highlights one of the major questions for this option – how does central dispatch (which covers the balancing market using inputs into the Pool) interact with the results of the DAM and IDM?

At the minimum, this requires changes in the imbalance settlement process to allow for the DAM and IDM results to be taken into account. However, these results may be at portfolio rather than unit level (whereas imbalance settlement in Greece currently done at unit level), so a process would need to be in place for translating between portfolio-level results in coupling markets (DAM and IDM) and unit-level results in Greece (Pool and dispatch).

Ignoring the portfolio/unit distinction, the settlement process could treat any deviation between the dispatch quantity and the metered volume as uninstructed imbalance and hence subject to the SIMP.

This raises one challenge namely that uninstructed imbalances are cleared at the same prices as instructed deviations. This may be judged not to be consistent with the requirement for (uninstructed) imbalance settlement prices to incentivise parties to be in balance. Therefore, alternative prices may be considered – e.g. using the clearing price from **accepted** bids for balancing (if these can be identified robustly).

Furthermore, problems can arise when the market position does not match the dispatch quantity (when both are being determined in parallel through separate processes). The issues arise because the Target Model and the existing Greek market arrangements have different approaches to the interaction between dispatch and markets (or schedules).

The dispatch of the system in the current Greek market is based on bids into a gross mandatory pool onto D-1, with no subsequent trading or re-bidding opportunities. In contrast, the Target Model is based on the results from a set of voluntary ex-ante markets providing the starting point for dispatch decisions that are designed to cover residual differences between supply and demand. Balancing actions are treated separately, as 'deviations' from the participants' own scheduled volumes, and are based on a revised set of commercial offers typically made around the time of gate closure for energy trading.

This problem could materialise in distortions in the bidding into the IDM (depending on dispatch) or incentives not to respect dispatch (with possible security of supply implications). For example (depending on particular market design and circumstances), the generator could be incentivised to sell additional volumes above its dispatch quantities into the IDM.

If dispatch takes precedence, then DAM and IDM participants may be exposed to unmanageable commercial risks, which will affect participation levels in the market coupling.

However, if the schedule takes precedence (i.e. participants are not obliged to offer balancing services and are not subject to central dispatch), this will remove one of the key tools that the TSO has to ensure security of supply.

The result could be that the TSO looks to use ancillary service contracts outside of the current dispatch mechanism e.g. warming contracts, reserve contracts. In GB, pre-gate energy transactions are also possible although this could be problematic to introduce in Greece. This represents additional change from the current design, particularly if new markets are introduced. Alternatively, if bilateral contracts are used, there will be questions about transparency.

One further compliance question for the current Greek arrangements is that intermittent generation is deemed to be dispatched at its metered volumes, with all deviations from DAS being treated as activated balancing energy (rather than as uninstructed imbalances). It is unclear as to whether this is compliant with equal treatment of intermittent generation in balancing arrangements as required under the Target Model, although we note that like Greece, most other European countries currently have feed-in tariffs for renewable generators with no concept of balance responsibility. If this arrangement was changed, then there may be question marks about whether the TSO should continue to submit the forecast for intermittent generation into the Pool.

5.3 The NWE option

The description of this option and our recommendations for change are based on the markets of Western Europe, which were a key driver for the development of the European Target Model. These markets are also the foundation of the PCR (Price Coupling of Regions) project. This is a project by the 6 biggest Power Exchanges in Europe developing a common price algorithm to be used as a single price coupling mechanism across Europe.

Therefore, the main issue for this option is about the suitability of the design for Greece (given the extent of the change from the current market design) rather than compliance with the Target Model.

Under this option we have a complete reform of the market with the removal of key features of the current Greek market, such as:

- gross mandatory pool;
- current bid formats (including technical data);
- central dispatch;
- co-optimisation of energy and reserve; and
- optimised imbalance prices (i.e. based on perfect hindsight rather than actual balancing actions).

We also assume the removal of the Cost Recovery Mechanism; and (implicitly) the Capacity Adequacy Mechanism. However, we note that a number of the markets in Western Europe either have or are considering the introduction of capacity mechanisms. Arguably, national capacity mechanisms would not be within the spirit of the Target Model but this remains a matter of debate at a European level.

Figure 18 summarises the NWE option, presented in the structure of our six relevant building blocks, with Figure 19 showing the key components of the market under this option (using the Nordic market as an example).

This option is centred on trading in the Day Ahead Market (DAM) combined with bilateral trading and forward markets organized in Greece, with the Intraday Market (IDM) acting as an adjustment market. If RAE wishes to develop this option further, it would be helpful to think about the implications of such an option (given current level of market concentration in Greece) for the market data requirements to deliver transparency, and its approach to market monitoring.

We propose that separate balancing markets are introduced to replace the procurement and activation of balancing resources using the Pool (which is no longer in place under this option). Figure 20 shows how a balancing market solution could be used to procure all three of the reserve types identified in the EB FG[45] – frequency containment reserves, frequency restoration reserves, and replacement reserves (as detailed in Section 2.2.1 of this report).

[45] To undertake the task of secure real-time operation, the TSO needs to procure a set of balancing products and/or ancillary services. Procurement of at least a part of such products and services is normally undertaken through the operation of market places – the so-called balancing market being the main market for this purpose. The ideal procurement of such products and services in general will depend on the nature of the products and the amount of potential market participants.

Figure 18 – Building block summary of the NWE option

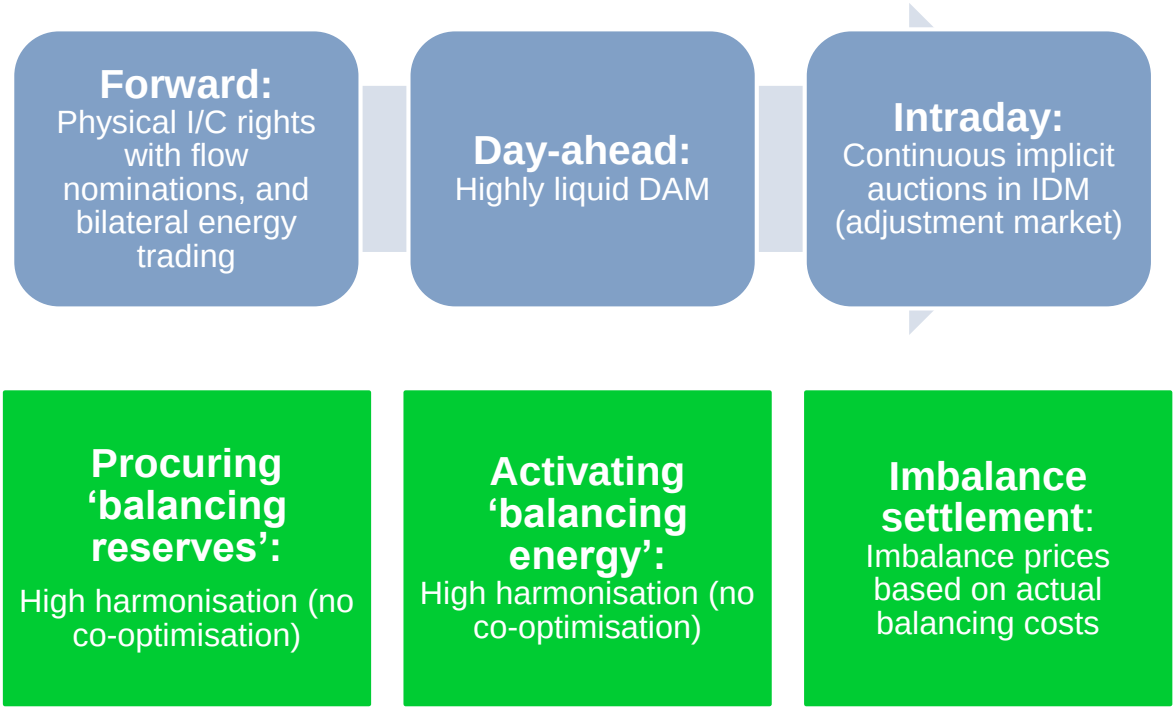


Figure 19 – Example of conceptual design of the market under the NWE option

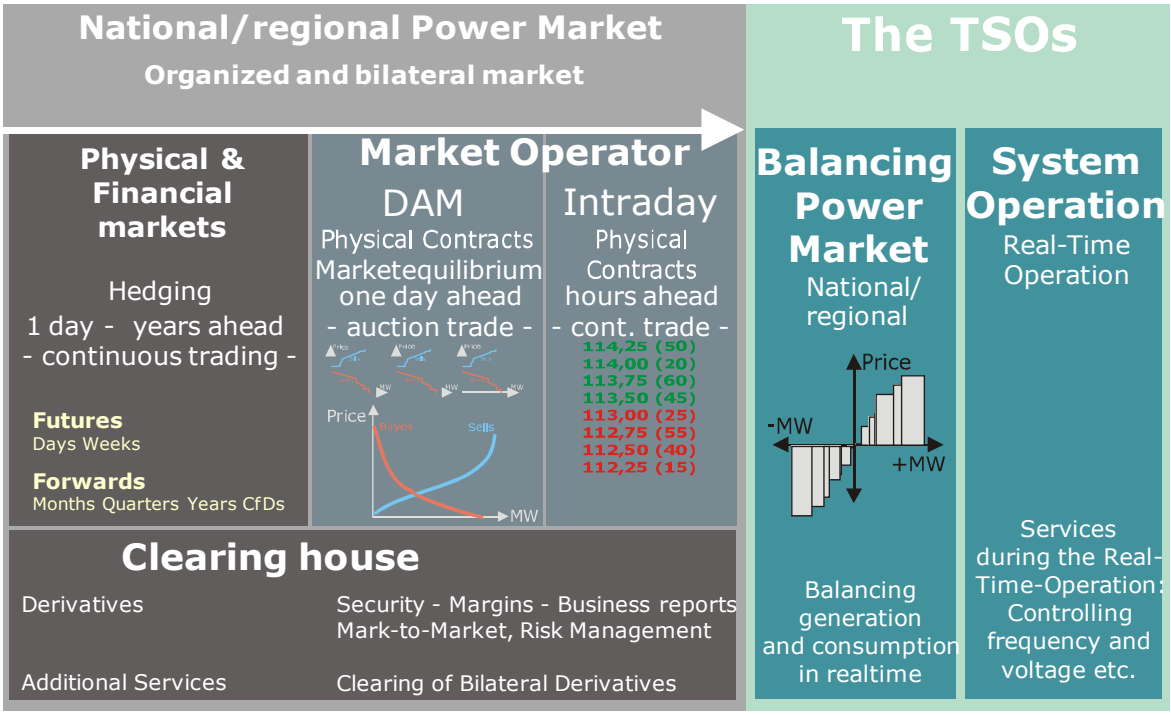
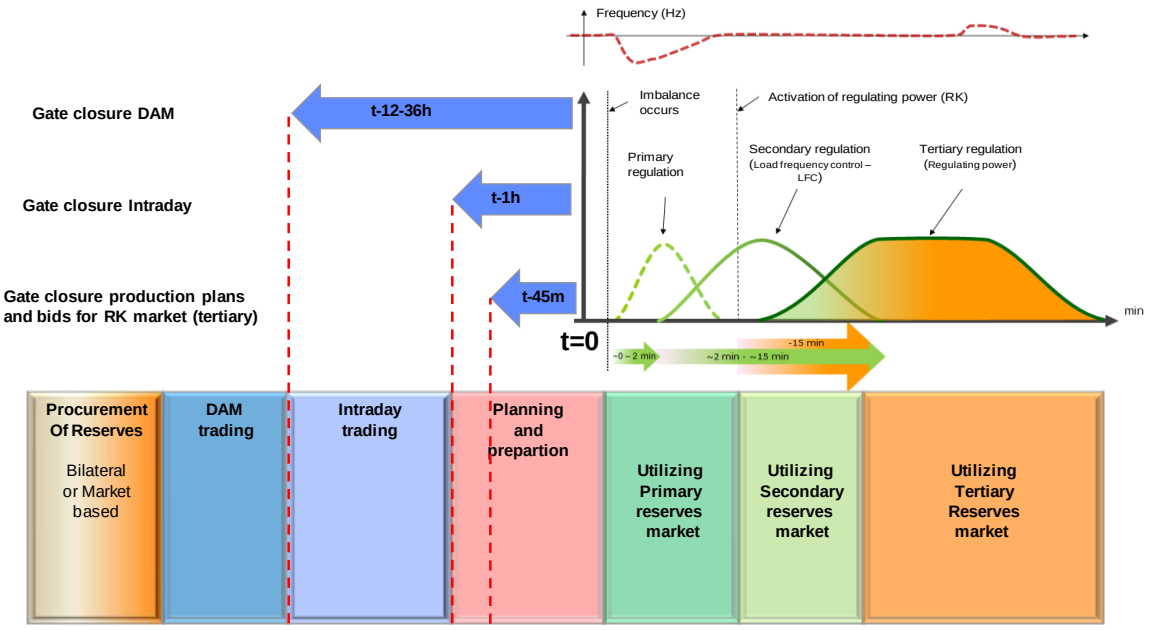


Figure 20 – Possible operation of a balancing market



5.3.1 Forward

A forward energy market is introduced for both physical and financial products. The financial contracts would typically use the DAM market clearing price as reference price.

Market participants can trade energy products over timeframes varying from one day up to years prior to delivery. Given the current market dominance of the incumbent in Greece, it may be required to act as a market maker to give other market participants the opportunity to buy or sell longer term contracts. An alternative market power mitigation measure would be to introduce Virtual Power Plant Auctions.

It is vital that policy-makers promote effective competition between organized markets and bilateral trade.

5.3.2 Day Ahead

As described for the Adaptation option, a Day Ahead Market (DAM) would be implemented to allow all available interconnection capacity to be allocated through a single price coupling algorithm (across Europe) based on the marginal pricing principle (see Section 5.2.2 for more details).

Although central dispatch has been removed in this option, NWE markets would typically have requirements for market participants to submit notifications of physical positions to allow for system operation planning. Indeed, one of the areas of debate around the July 2012 draft CACM NC has been the proposed requirement for generators to submit physical information to TSOs on D-2 to populate the Common Grid Model used to calculate available capacity on interconnectors (under the provisions of Article 18).

In addition to simple energy bids (stepwise, and linear interpolation), there are a number of sophisticated bidding options available in the DAM in the NWE option, although these are not as technical/complex as the bid formats used in Hybrid option DAM.

These include:

- flexible hourly bids (price/volume pair that could be activated in any single hour, and is scheduled for hour with highest system price);
- fill or kill block bids;
  - profile block;
  - linked block; and
  - convertible into standard independent hourly bids if the block bids is not accepted and system price reaches price cap of €2000/MWh in block period).

5.3.3 Intraday market

As detailed for the Adaptation option (see Section 5.2.3), compliance with the Target Model requires an Intraday Market (IDM) that allows continuous intraday trading with pricing of congestion (whilst meeting the various process requirements set out in the draft CAMC NC).

In the NWE option, we do not propose the introduction of periodic intraday auctions to complement the continuous trading platform, partly because it is not clear how this would operate in practice. It is also not a feature used in the NordPool market that we used as a reference for this option.

5.3.4 Procuring balancing reserves

Figure 20 shows that (as at present), reserves may be procured over a range of timescales to ensure access to balancing market bids. This could occur right up to the day ahead stage.

5.3.5 Activating balancing energy

Under the NWE option, the balancing market is separate from the wholesale energy market. In this balancing market, the TSO is the sole counterpart, buying or selling power on behalf of parties in imbalance (with imbalance pricing used to encourage market players to remain in balance). Depending on design of the balancing markets, bids and offers will be used to handle both imbalances and congestion management.

Such balancing markets therefore form an integral part of the overall wholesale electricity trading arrangements and time schedules. Indeed, whilst the DAM can be considered to be the most important balancing tool for the TSO, the existence of an efficient DAM is also dependent on the balancing market operation.

Before gate closure of trade, generation and, in some cases, consumption participants must notify the TSO of the expected physical positions at real time. There is also a time schedule (normally connected to gate closure of trade) for submission of bids to the balancing market.

There are different types of balancing resources and they can be differentiated by the following characteristics:

- activated automatically or manually; and
- availability ensured by contract (through procurement of reserves) or not.

In the balancing market operation, automatically activated resources act first, and are generally limited to resources procured through a reserve market. In contrast, resources

used to provide manually activated balancing energy may or may not have had its availability ensured through procurement in a reserve market.

Following the gate closure for the IDM, the Balancing market operator makes calls on the bids and offers of generation and load in order to balance the system at the least cost. To ensure compliance with the Target Model, this will need to be done using a merit order (i.e. ranking of bids by cost).

In Europe, most countries have adapted to a two-price system, i.e. that there will be separate prices for up and down regulation. The prices are set based on a marginal price basis, i.e. that the bid price of the last used resource is the one that defines the price for regulation (one for up-regulation and one for down-regulation).

There is typically one exception and that is where the TSO needs to choose a bid that is out of merit due to operational reasons (e.g. for locational reasons). These are typically paid as bid, but these will not be part of the calculation of the price for up- and down regulation. However, it is not clear how such arrangements will fit with the requirement of the EB FG – for example, it may be argued that the generator is providing a network service rather than an energy balancing service.

5.3.6 Imbalance settlement

Under this option, there is balancing responsibility for all wholesale market participants, which should provide the market participants an incentive to trade into balance before entering real-time operations.

Imbalance costs are typically based on actual balancing actions taken by the TSO, which requires it to be able to distinguish between actions taken for energy balancing (which should be included in costs) and system balancing actions taken for network purposes (e.g. to relieve congestion), the costs of which should not be reflected in imbalance prices. It can be very challenging to separate energy from system balancing actions, and this is an area that Ofgem (the UK energy regulator) is looking at again in its current review of imbalance arrangements in the British electricity market.

The practice from several of the Western European markets is to use the price for the activation of energy in the Balancing market as the Imbalance price as well. This means that the price for balancing power in the dominant direction (i.e. the direction – up or down – with the highest volume in the trading period) will be used as the Imbalance price. In a number of Western European markets, there are dual cash-out arrangements, whereby if you are out of balance but in the “correct” direction,(i.e. your imbalance is helping the system); you will not be charged the imbalance price, but the DAM price (i.e. you will not have any cost of your imbalance).

To comply with the Target Model, the imbalance settlement period will need to be 30 minutes or shorter, which is already the case in some NWE markets (e.g. Belgium has a 15 minute imbalance settlement period, alongside hourly settlement in the wholesale electricity market).

5.4 Hybrid option

In our two options, we have assumed that the day-ahead market coupling is carried out through a traditional power exchange, such as NordPool.

In our third option, the Hybrid option, we consider the issues around introducing price coupling through a ‘voluntary’ pool for the DAM as used in Spain and Italy, which are also

involved in the PCR project. The pool is voluntary to the extent that physical bilateral contracts can be struck in the forward timescale. However, any available generation without a bilateral contract must then participate in the pool.

Like the NWE option, the Hybrid option requires the removal of the current **gross mandatory** Pool (with co-optimisation) that is currently in place in Greece.

In this option, we use the arrangements in Spain as a benchmark, just as NordPool provided a benchmark in our NWE option. This benchmark is designed to provide insight into the design around our building blocks in relation to the compliance model. For the avoidance of doubt, we are not proposing the adoption of the entire Spanish regulatory and market framework (in respect to features such as the coal subsidy[46] or electricity suppliers of last resort).

The Spanish example is a useful benchmark for the Hybrid option because it is an example of market coupling in practice (between Spain and Portugal), allows bilateral contracting as well as the pool, and uses the most technical/complex bids accommodated by the proposed PCR algorithm (as discussed in Annex C).

The pool is actually an Iberian electricity market (MIBEL) covering Spain and Portugal. A market splitting mechanism is used (as in NordPool) when constraints between Spain and Portugal occur. Since the launch of MIBEL in 2007, the number of hours with identical prices in Spain and Portugal has increased from around 20% to approximately 90% in 2011. Although implicit auctions are used at the day-ahead stage for allocation of capacity between Spain and Portugal, explicit auctions are still used at the day-ahead stage for interconnector capacity between Spain and France.

There are opportunities for forward contracting, both bilaterally (OTC) and through the OMIP forwards market.

There are three main markets falling under the Spanish Pool (each of which has its own prices determined by a marginal pricing algorithm):

- Daily market, for the purchase and sale of electricity for the following day on an hourly basis – commenced on 1 January 1998.
- Intra-day market, for the adjustments that may be required to the supply or demand of energy after the variable daily schedule has been fixed. This market started operating on 1 April 1998.
- Ancillary (or complementary) services and balancing market (which is operated by REE, the Spanish TSO).

These markets will determine the price and quantity that will determine the amounts to be received by sellers and similarly for buyers. Each market participant has a final hourly price which is a function of his/her participation in each of the markets – daily, intra-day and complementary services.

The final electricity price is made up of three components:

- the price of energy, which includes:
  - the price resulting from the settlement in the daily market;

46 This results in adjustments to the daily schedule (but not to the price) to include subsidised coal plant at the expense of plants in the schedule with highest CO2 emissions (not highest costs).

  - the price of the deviations deriving from the technical restrictions included in the Viable Schedule; and
  - the price obtained in the settlement of the intra-daily market.
- the cost of the Capacity payment; and
- the cost of the corrections needed as a consequence of deviations or alterations in the Final Hourly Schedule, i.e. ancillary services.

Figure 21 summarises the hybrid option, presented in the structure of our six relevant building blocks.

Figure 21 – Building block summary of the Hybrid option

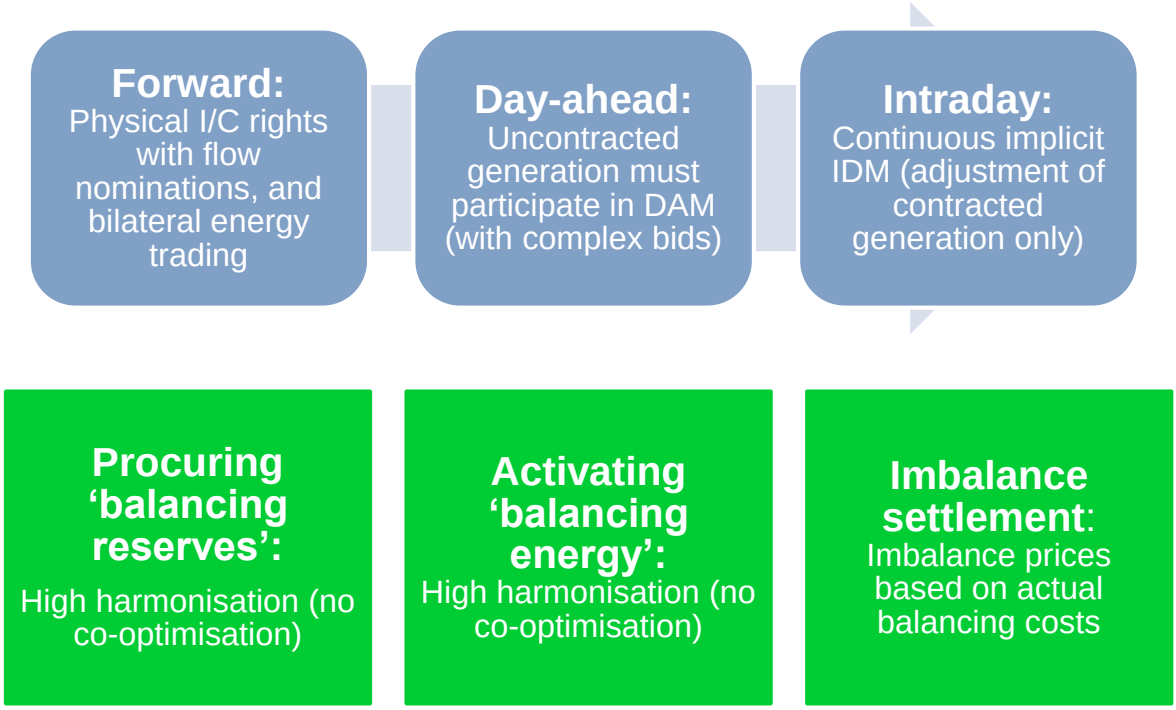
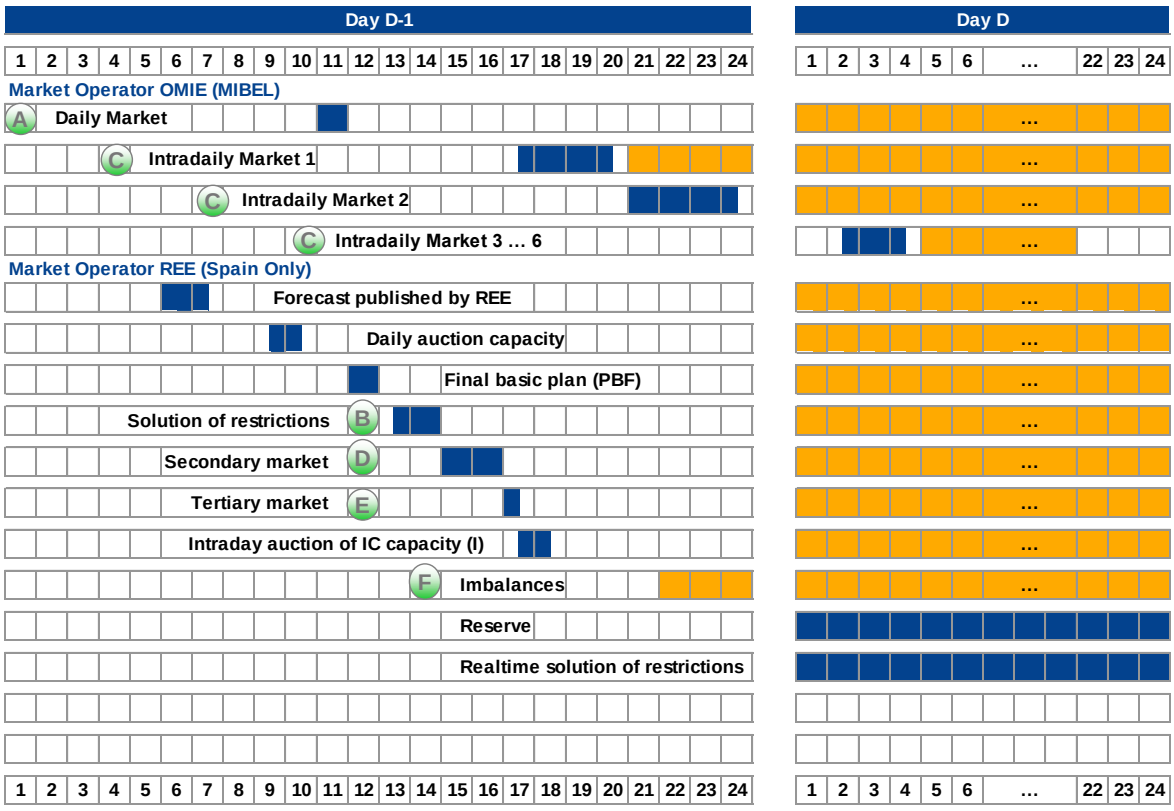


Figure 22 – Summary of the workings of the Spanish Pool

A	**Daily Market**	> Day-Ahead (OMIE) Price for each hour (SMP) > Product of bids and offers by generators and suppliers > Price set at intersection of supply and demand
B	**Restrictions**	> System Operator (REE) determine the technical restrictions (i.e. capacity constraints on network) > Adjusts merit order to solve restrictions
C	**Intraday Markets**	> Intradaily market (OMIE), allows players to adjust their offers made in the daily market within 6 sessions
D	**Secondary Market**	> System Operator (REE) buy short response balancing services to balance the system in real time > Typical response time is <100s (only few generators)
E	**Tertiary Market**	> System Operator (REE) buy medium response balancing services to balance the system in real time > Typical response time is <15 min
F	**Imbalance**	> System Operator (REE) buy or sell energy to balance the system, if REE forecasts more demand than the final one, it would buys the requirement in this market

Figure 23 – Market procedures and timings



5.4.1 Forward

Under the Hybrid option, there is the opportunity for market agents to freely negotiate physical contracts for electricity over the forward timescale. The commercial terms of these contracts are kept private but the volumes agreed have to be notified to OMEL.

Since 2007, there has been a shift towards bilateral contracts away from the day-ahead pool in Spain, with bilateral contracts now representing around one-third of energy production. This has been caused in part by the regulator trying to force distribution companies to contract quarter-ahead for demand in the regulated market, so that the government will know the likely tariff deficit ahead of time. This has led to distribution auctions that are separate from the Pool (and are quarter-ahead).

Although a derivatives market (OMIP) has been in operation since 2006, the liquidity of this market is very limited so far, being the OTC market more commonly used. In OMIP, both physical forwards and financial futures contracts are traded[47]. Specifications of these contracts are standard (i.e. volume, underlying, minimum change in price, etc). Any profit or loss is calculated and settled (mark to market) on daily basis. Transactions are registered in trading and compensation accounts in order to proceed with the financial settlement.

The trading session in OMIP comprises three different phases:

- opening session – where the trading members can only modify existing orders, but they cannot close new deals;
- trading phase – active trading takes place, new deals are closed; and
- closing session – where the trading members are once again only allowed to modify existing orders, but they cannot close new deals.

5.4.2 Day-ahead

The difference between a voluntary pool and a NWE-style power exchange is typically much smaller than the difference between a gross mandatory pool and a NWE-style power exchange. However, while this option shares similarities with the NWE option (most notably in the abolition of the gross mandatory pool), it is not identical.

Key differences of the DAM in the Hybrid option include:

- all bids to the market are unit based (rather than portfolio based);
- all available production units that have not contracted in the forward bilateral market are required to be offered into the pool;
- more complex bidding formats than seen in the NWE option;
- available generators (subject to eligibility) receive a capacity payment from the Pool[48] (made up of an availability incentive and an investment incentive).

The requirement for uncontracted generation to bid into the Pool is designed to prevent any physical withholding of capacity. However, this capacity can be bid in at the theoretical price limit ('economic withholding'), which is set relatively low at €180/MWh

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47 Forwards contracts are not subject of mark to market procedure while futures contracts are.

48 The eligibility rules for the capacity payment mean that it is collected mainly by CCGTs.

compared to the price limits used in other DAMs, e.g. NordPool (€2000/MWh), Belgium (€3000/MWh), Italy (€3000/MWh).

The bid formats used in the DAM in the Hybrid option includes more complex bidding formats than in the DAM in the other two options. Simple bids are allowed as well as complex bids. Simple bids are price-energy steps (within the allowed price limits of €0/MWh and €180/MWh) that are increasing for generation and decreasing for demand.

Complex bids are those that incorporate complex sale terms and conditions and those which, in compliance with the simple bid requirements, also include one or some the following technical or economic conditions:

- **Load gradients.** This condition is a maximum variation in output (in MW/minute) to ensure that matched output in consecutive hours is technically feasible.
- **Minimum income**[49]*.* The generator is only matched in the schedule if its income level for a defined period is above an established fixed amount, plus a variable payment for every matched kWh.
- **Scheduled stop.**[50] This is activated when the minimum income condition is not fulfilled for the next day but the generator is scheduled to be producing in the last hour of the current day. The generator has a maximum of 3 hours to stop producing on the next day (for which the minimum income condition was not fulfilled) so that it does not have to drop from full production at the end of one day to zero production at the start of the next day. The condition is implemented by accepting only the first step of the first 3 hours as long as the production level decreases from hour to hour.
- **Indivisibility**[51]**.** This seldom-used condition enables a minimum operating value to be fixed in the first block of each hour. This value may only be divided by the application of the load gradients declared by the same agent, or by applying distribution rules if the price is other than zero.

Our Hybrid option would also allow all of these bid formats and conditions to be available to demand (which is not currently the case in the Spanish pool). In particular, the maximum payment condition (the mirror of the minimum income condition) may be of interest to demand customers[52].

The NEMO also takes into account bilateral physical contracts, any generation exempt from bidding in the Pool and international exchanges to construct the Base Daily Operating Schedule (Base Schedule).

Under the current Spanish arrangements, the TSO determines the Viable Schedule by assessing the technical restrictions (including the need for complementary services) that may apply to the implementation of the Base Schedule.

Technical restrictions on the interconnector are resolved first. To solve technical restrictions, the TSO agrees with the NEMO to withdraw some plant (such as in areas

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49 In the Spanish arrangements, the Minimum Income Condition is defined across the whole day, but in theory, it could be defined for any agreed time period.

50 In practice, this could be implemented through the Load Gradient condition, and hence a special condition is not strictly required for this circumstance.

51 Not applicable to hydro units.

52 As noted in 'Day-Ahead Electricity Market: Proposals to adapt complex conditions in OMEL', Nestor Sanchez Maria, July 2010',

where there is a constraint on export of generation) and schedule other plant (such as in areas where there is an import constraint). Constrained-off plant will not receive any compensation, whereas plant scheduled-on in this way are paid their bid price (which will be above the market clearing price paid to other generators). The daily market price does not change, but the cost associated with resolving the technical constraints is included in the final price and is spread across all purchasing units.

This technical assessment is not an integral part of the hybrid option.

5.4.3 Intraday

After the publication of the Viable Schedule based on the DAM, OMIE participants can adjust their position through a number of intraday sessions (or periodic auctions), which will raise challenges for its compliance with the Target Model.

The following parties can participate in the intraday market:

- owners of generating units authorised to bid into the daily market;
- owners of purchasing units authorised to bid into the daily market; and
- holders of physical bilateral contracts who have communicated the execution of their contracts to be included in the daily operating schedule.

Bidders can participate in this market under the requirement that they respect previous commitments made for the provision of complementary services. Generating units have to have a bilateral contract or a contract from the DAM.

In the intraday market, a previous energy provider can now also be net purchaser and vice versa.

Simple and complex bid formats are also used in the IDM in this option. The complex bids include some of the same ones as used in the DAM (load gradient, minimum income condition) and some new ones:

- **Complete acceptance in the matching process of the first block of the bid** – this establishes a profile for all the hours of the intraday market, which may only be matched if this is matched in the first block of all the hours. This enables the production or purchase unit schedules to be adjusted to a new profile; if this is not possible in one part, the previous schedule can be left without modifying any of the hours individually. This option is used when the programming of certain hours is only possible if this can also be done in others, such as in order to bring forward the start-up or stoppage process, avoid boiler bottlenecks, etc.
- **Complete acceptance in each hour in the matching period of the first block of the bid –** only the first block will be programmed in a specific hour if it is not matched completely, and all the blocks in that hour will be withdrawn, but the bid presented for the other hours will not be withdrawn. This option is useful for programming groups that produce (technical minimum) or consume (pumping consumption), a minimum value or nothing. It may also be useful for consumers to notify a similar situation.
- **Minimum number of consecutive hours of complete acceptance of the first block of the bid –** condition of a minimum number of consecutive hours with complete acceptance of the first block of the bid may be applied when the production or purchase unit must produce or stop consuming consecutively at least a number of hours. The same condition would apply to consumers who, for example, are unable to operate a plant for a number of hours below the number specified in the bid.

- **Maximum matched power –** enables bidding units with limited available power (in MWh terms) to bid in all hours but limiting the matched value to an overall maximum power. This condition is necessary due to the volatility of prices in the intraday market between hours, which make it impossible to determine the hours in which the production or purchasing units may be matched; however this condition has a limit on the power that they can sell, such as in the case of pumping generating units.

In the Hybrid option, we have only considered the use of continuous intraday trading as this is a minimum requirement at the intraday stage. The CACM NC also allows the use of complementary periodic auctions. Indeed, Italy and Spain (which currently use day-ahead pools) are planning to continue to operate intraday periodic auctions alongside the continuous trading. Therefore, RAE could monitor intraday developments in these markets, particularly if the Hybrid option is of interest for further development.

5.4.4 Procurement of balancing reserve

The TSO examines the Base Schedule to assess the need for ancillary services, which can be categorised as either complementary services or real time management, using the Spanish market as an example).

The complementary services can be obligatory or at operator will, as shown in Figure 24.

Figure 24 – Complementary Services

Obligatory services	Operators services
• Primary regulation • Voltage control	• Secondary regulation • Tertiary regulation • Exceeded voltage control • Service replacement

For secondary reserve (to accommodate errors in demand forecasting, to provide contingency arrangements for generation failures and to restore frequency response capabilities), the TSO publishes a provisional program for the hourly reserve requirements for the following day. This then opens the period for receiving offers for the provision of secondary reserve.

5.4.5 Activating balancing energy

The process for activating balancing energy under the Hybrid is basically the same as that described under the NWE option (in Section 5.3.5) The TSO is the sole counterparty in the balancing market, which is separate from the wholesale energy market. Depending on detailed design of the balancing markets, bids and offers will be used to handle both imbalances and congestion management.

Before gate closure of trade, generation and, in some cases, consumption participants must notify the TSO of the expected physical positions at real time. There is also a time schedule (normally connected to gate closure of trade) for submission of bids to the balancing market.

Following the gate closure for the IDM, the Balancing market operator uses a merit-order approach to make calls on the bids and offers of generation and load in order to balance the system at the least cost.

There can be separate or common prices for up and down regulation – in either case, the prices are based on the bid price of the last used resource (i.e. a marginal price). Exceptions may be made for bids chosen out of merit by the TSO for operational reasons (e.g. location), where it may be argued that the generator is providing a network service rather than an energy balancing service.

Under the current Spanish system, the imbalance management process follows the intra-day market but precedes the real time management of the system, which would require the ancillary services contracts to be called. This process is used to manage any changes that have occurred to plant availability, purchasing agents' load expectations and REE's demand forecasts. The hourly average deviation has to be greater than 300MW. If not, the deviation is resolved through the ancillary services market.

REE publishes the deviation value and accepts the lowest cost bids required to cover it. All accepted bids receive the marginal price and the cost is paid by the agents who caused the deviations.

5.4.6 Imbalance settlement

As for the NWE option, the imbalance costs are based on actual balancing actions taken by the TSO. This then raises the challenge of the TSO being able to distinguish between:

- actions taken for energy balancing (which should be included in costs); and
- system balancing actions taken for network purposes (e.g. to relieve congestion), the costs of which should not be reflected in imbalance prices.

As for the NWE option, it is possible to have dual cash-out arrangements and to use the price for the activation of energy in the Balancing market as the Imbalance price as well.

To comply with the Target Model, the imbalance settlement period will need to be 30 minutes or shorter.

6. TRANSITION ROADMAP

In Chapter 5, we described different options for the Greek electricity market design to comply with the requirements of the Target Model. These options could represent different steps in the evolution of the Greek market design, with the Adaptation option perhaps being more suitable for speedy implementation in line with the target date for the single electricity market of 2014.

Therefore, this chapter considers three aspects that would be helpful to RAE in preparing a detailed roadmap for transition:

- summary of the changes required to the current Greek arrangements to implement the options;
- listing of possible intermediate transition steps in moving beyond the minimum change described in the Adaptation Option; and
- options for introducing the central systems required to implement the coupled markets at day-ahead and intraday stage.

6.1 Changes required to implement the Target Model

Table 16 summarises the minimum changes needed across all three options in order to implement the Target Model.

Our gap analysis highlights that major changes would be needed at the day ahead stage (in terms of both market design and market processes) and the intraday stage (given that no such market currently exists in Greece). The Target Model requirements in these areas are clearly defined in the CACM NC (see Sections 2.3.5 and 2.3.6)

This means that across all three options, the minimum changes are:

- the introduction of a Day Ahead Market (DAM) to implement price coupling in line with the Target Model; and
- the introduction of an intraday market (IDM) and supporting trading platform.

Compliance will require a number of changes to market operations:

- the definition of the trading day would need to match the Target Model requirement of 0100 to 0100 Greek time;
- timing of market processes must be harmonised (e.g. interconnector capacity calculation, bid submissions etc);
- current Greek bid formats are unlikely to be supported by the price coupling algorithm;
- market participants must change their processes, as for example demand would need to submit prices into the DAM; and
- the current price floor and in particular the price cap in Greece may be ruled to be distorting cross-border trade and hence could need to be removed as part of the harmonisation provisions included in the July 2012 Draft of the CACM NC.

The proposed changes for balancing and imbalance are based on the requirements set out in the April 2012 draft of the EB FG. The detailed implementation of the shorter imbalance settlement period change, e.g. in terms of system requirements, should be reviewed once the FG are finalised.

Table 16 – Changes needed under each option

Building block	Common
Zone definition	Introduction of procedures for (regional) zone definition process
Capacity calculation methodology	Testing of Flow Based methodology
Allocation of capacity between timeframes	Introduction of process for regulatory approval of capacity allocation between timeframes
Forward	Introduction of common European platform for (re)trading of long-term interconnector rights: Removal of daily explicit auction for interconnector rights
Day-ahead (DAM)	Introduction of a DAM for price coupling with timings/market processes in line with Target Model requirements (e.g. trading day starting at 0100 Greek time)
Intraday (IDM)	Introduction of IDM with (at least) continuous trading and supporting trading platform, with timings/market processes in line with Target Model requirements
Procuring balancing reserves	Some harmonisation of processes (and potentially products) with neighbouring countries
Activating balancing energy	Some harmonisation of processes with neighbouring countries; Move to marginal pricing for procurement of downwards balancing energy (currently cost-based price)
Imbalance settlement	Settlement period to be reduced to 30 minutes; Cost-reflective pricing for upwards uninstructed imbalances (currently zero)

Table 17 summarises the additional changes required under each option, beyond the minimum changes described in Table 16.

Table 17 – Additional changes needed under each option

Building block	Adaptation option	NWE option	Hybrid option
Forward	Current DAS to be run earlier on D-1	Forward bilateral trading options (physical and financial)	Forward bilateral trading options (physical and financial)
Day-ahead (DAM)	None (all new)	None (all new)	Introduction of new bidding conditions and formats
Intraday (IDM)	None (all new)	None (all new)	None (all new)
Procuring balancing reserves	None (co-optimisation in the Pool)	Ancillary services market(s)	Ancillary services market(s)
Activating balancing energy	Move to marginal pricing for both upwards and downwards balancing energy	Separate balancing mechanism	Separate balancing mechanism
Imbalance settlement	Revised calculation of imbalance volumes to take account of results from coupling markets	Systems for calculating actual costs in energy balancing (as opposed to network actions)	Systems for calculating actual costs in energy balancing (as opposed to network actions)

6.1.1 Additional changes needed for Adaptation option

For the Adaptation option, the two key additional changes under this option are:

- **current DAS to be run earlier on D-1 so that it acts as a new 'forward' market ahead of the DAM** (which effectively operates as an adjustment market); and
- **revision of the calculation of imbalance volumes to take account of the results of the price coupling markets (DAM and IDM),** which therefore imposes extra data management costs on market participants**.**

6.1.2 Possible measures to support DAM liquidity development in the NWE option

The success of the NWE option depends upon sufficient volumes nominated at DAM (liquidity). Therefore, it may be helpful to introduce transitional incentives for eligible consumers and public suppliers to source from the DAM to promote and secure market liquidity.

During the transitional period, volumes at a regulated and favourable price may be gradually reduced. The relevant authorities, e.g. regulatory authority and/or Ministry, must decide on the duration of the transitional period.

6.1.3 Possible measures to support development of separate balancing market

In the NWE and Hybrid options, the removal of the gross mandatory pool (where energy and reserves are co-optimised) means that the development of specific Real Time

Balancing Market/Ancillary /Reserve markets are vital to ensure balance management. This will require the development of new trading platforms.

There is a need to decide which of the balancing products to procure through a market solution and which to procure bilaterally or through other arrangement, for example technical requirements with or without compensation.

These measures could include:

- incentivising eligible customers to nominate volumes at the DAM;
- ensuring that public suppliers purchase parts of tariff customers' consumption from the DAM; and
- make TSO purchase main grid losses from the DAM.

In some balancing markets in Western Europe, generators are legally bound to propose to the TSO all of their available capacity. This may be suitable as a transition measure in the introduction of a new balancing market in Greece.

6.2 Possible transition steps

Our options could also be seen as possible different states of the Greek market as it evolves over time, particularly with scope to move from the Adaptation option to either the NWE option or the hybrid option. Therefore, we have identified a number of possible transition steps for moving beyond the basic Adaptation Option:

- make the Forward Pool on D-1 voluntary rather than mandatory;
- remove co-optimisation from the Forward Pool (alongside the development of new reserve markets);
- designate a central agency with responsibility for converting bids from the current Greek format into bids accepted by the market coupling algorithm; and
- allowing rebidding to the IDM to be considered in dispatch.

The steps are not necessarily designed to be followed in the order set out above.

6.2.1 Making the gross pool on D-1 voluntary

One of the issues raised by the Adaptation option is whether or not it would be deemed to be compliant with the Target Model given that the DAM is effectively relegated to an adjustment market. In this option, the Pool is retained (immediately before the DAM), as a market power mitigation measure because it should (in theory) provide greater transparency on bids, as well as providing a liquid trading option for new entrants.

Therefore, a possible variant is to retain the pool but make it voluntary – this may be a transitional measure in response to the development of more effective competition. If not all of the market submits bids to the Pool, this raises questions for the activation of balancing energy, and the imbalance settlement process.

The working assumption in the Adaptation model is that the activation of balancing energy is still based on data submitted to the Pool. Therefore, if the inputs to the Pool become an incomplete set of data, this could exclude some market participants. As a result, new balancing mechanisms may be required.

Similarly, in the event that only some of the market bids into the Pool, it may not be appropriate to use a full ex-post run of the Pool to determine imbalance prices. Instead,

there may need to be a move to only running the algorithm to cover deviations from the ex-ante Pool rather than a full ex-post gross optimisation.

This variant of a voluntary Pool could also be extended by holding back a certain amount of interconnection capacity for the Day Ahead market, to encourage liquidity in the market.

6.2.2 Remove co-optimisation from the pool

A second variant could be to remove co-optimisation from the Pool, possibly at the same time as making it voluntary. This could mean that there is less difference between the Pool results and the DAM results (as the algorithms may be more similar). However, this variant could then have significant knock-on effects on the reserve procurement processes, as a new procurement market would need to be introduced (e.g. in the form of an ancillary services market).

6.2.3 Conversion of 'Greek bids' into market coupling bids

As discussed above, one of the issues with the Adaptation option is the limited importance (and limited volume of trading) in the DAM. Therefore, one variant to encourage participation in market coupling could be for a central agency to take responsibility for converting bids from the current Greek format into bids accepted by the market coupling algorithm. However, this requires market parties to be comfortable with the allocation of the risk involved in this conversion – essentially someone would be exposed to the consequences of the prices and schedules differing between the gross mandatory pool and the Day Ahead market. One alternative is for the central agency to provide compensation (socialised across customers) to market participants negatively impacted by the conversion process.

This can be seen as an example of a virtual hub approach to market coupling. The Greek TSO or NEMO creates a "virtual hub" system in which the differences between the existing Greek markets and the DAM are hidden within this system; i.e. that bids from Greece are transformed into bids acceptable for a price coupling algorithm; or

A Virtual Hub means that a central Greek agency would create and operate an intermediate system between the internal Greek market and the neighbouring markets. This would imply a need to transform bids from the existing Greek market into a form that could be offered as part of a price coupling with Italy (and others).

This is the planned market coupling solution for Great Britain in the NWE (North-West Europe) project where a virtual hub system owned by National Grid 'hides' the complexity of the GB markets to the other participating countries in the NWE region. In GB they have bought this service from a service provider and it will be based on complex shipping arrangements between the involved parties. The main reason for having this is due to the fact that there are two competing PXs in GB.

The main advantage is of course that the market participants are not directly affected, i.e. they can bid as usual.

The main disadvantage would be that in the Greek case, this system will be a very complex one as the gap to bridge in bid structures is much larger than under the Virtual Hub solution for GB. This means that it might not be possible to create a solution that will ensure that the bids are comparable or compatible and thereby not deliver an optimal solution. Because it will be a complex system, this creates need for new system development as there is no system like this available today. Thereby the cost, risks and time to implement would be high.

6.2.4 Allow intraday rebidding for dispatch

When we discussed the Adaptation option, we noted the challenge of managing the interaction between dispatch and scheduling. This is because the positions that market participants would reach in their intra-day trading could deviate significantly from the requirements of the TSO. With a short gate closure (and whilst respecting the market results), the TSO would have limited time to see the final position of the generators and to instruct changes (to deal with reserve and contingency requirements).

One solution could be to allow intraday rebidding for dispatch, which should help to narrow the gap and reduce possible conflicts between dispatch and market results. This would obviously have implications for the TSO's systems in terms of information flows and iteration of the dispatch engine.

6.3 Options for implementation of market coupling systems

There are two broad options for the implementation of the market coupling systems (day-ahead and intraday) within Greece:

- Option A: Another market (such as the GME in Italy) offers this coupling through its current systems for Greek participants (like the Estonian/KONTEK solution implemented by Nord Pool Spot in the Nordic market).
- Option B: Greece implements its own systems to support a DAM and IDM (compliant with the Target Model) and couples with Italy on a bilateral basis (like the current Italy-Slovenia coupling).

In general, Option A is the simplest and quickest but would mean that Greece has less control over the coupling solution. Under Option B, Greece retains control but the implementation would probably take longer.

There are some key questions and decisions that are required to make any of these options work. These are:

- **what portion of the interconnector capacity should be kept for the coupled markets (i.e. Day Ahead and Intraday)?.** This could affect the liquidity in the markets and also create some incentives for participants to join (and possibly whether or not the option is deemed to be compliant).
- **how is the interaction managed with the internal market in Greece?** this will also depend on the overall compliance option chosen for the Greek market – for example, this interaction may be more complicated to manage under the Adaptation option.
- **what are the credit requirements and settlement processes imposed by another market under Option A?** This could distort trade (and competition) between different timeframes, and possibly have knock-on effects on the operation of the Greek market.
- **would the foreign market operator want to run the Greek zone?** Option A is reliant on the foreign market operator being happy to incorporate a Greek zone.

In the following sections, these two options are discussed in more detail.

6.3.1 Option A: In-sourcing DAM and IDM from another market operator

Under this option, Greece essentially will get the DAM and IDM but these would be fully operated and controlled by another market operator. This would be implemented by the other market operator adding a fully functional trading zone for Greece in their markets for

DAM and IDM. This can be compared with the temporary solutions used for both KONTEK and Estonia in the Nordic markets.

The main advantage with this solution would be that there would be limited (if any) effort required in **central** systems in Greece, although there would be cost implications for market participants. The time to market would be very short (depending on the adaptability of the systems of the foreign exchange). The central cost for this option to Greece would also be very limited, on the assumption that GME would be prepared to extend its systems to cover Greece in return for an expected stream of revenue from trading by Greek participants.

There are however some disadvantages with this solution. One issue would be that all market participants from Greece would have to comply with the market rules put in place by the foreign market operator including agreements, collaterals, payment schedules etc. This might be seen as a barrier to enter this market from the market participant's perspective and prove it hard to attract any liquidity. Market participants (and the regulatory authorities) would need to adapt their systems and processes radically. Another issue is that with this solution, Greece will have limited control over the development of the DAM and IDM.

6.3.2 Option B: Greek internal DAM and IDM

This option would require that the Greek NEMO would set up and operate a DAM and IDM solution for Greece. At a first glance, this might seem to be a huge effort that would require a long project period and substantial cost to implement. However, there are standard solutions for both the DAM and IDM market solutions that are available in the market today; both for sale or for lease whereby the Greek market could be operated by another entity. This would shorten the time to market for these systems, reduce the risks as well as the costs.

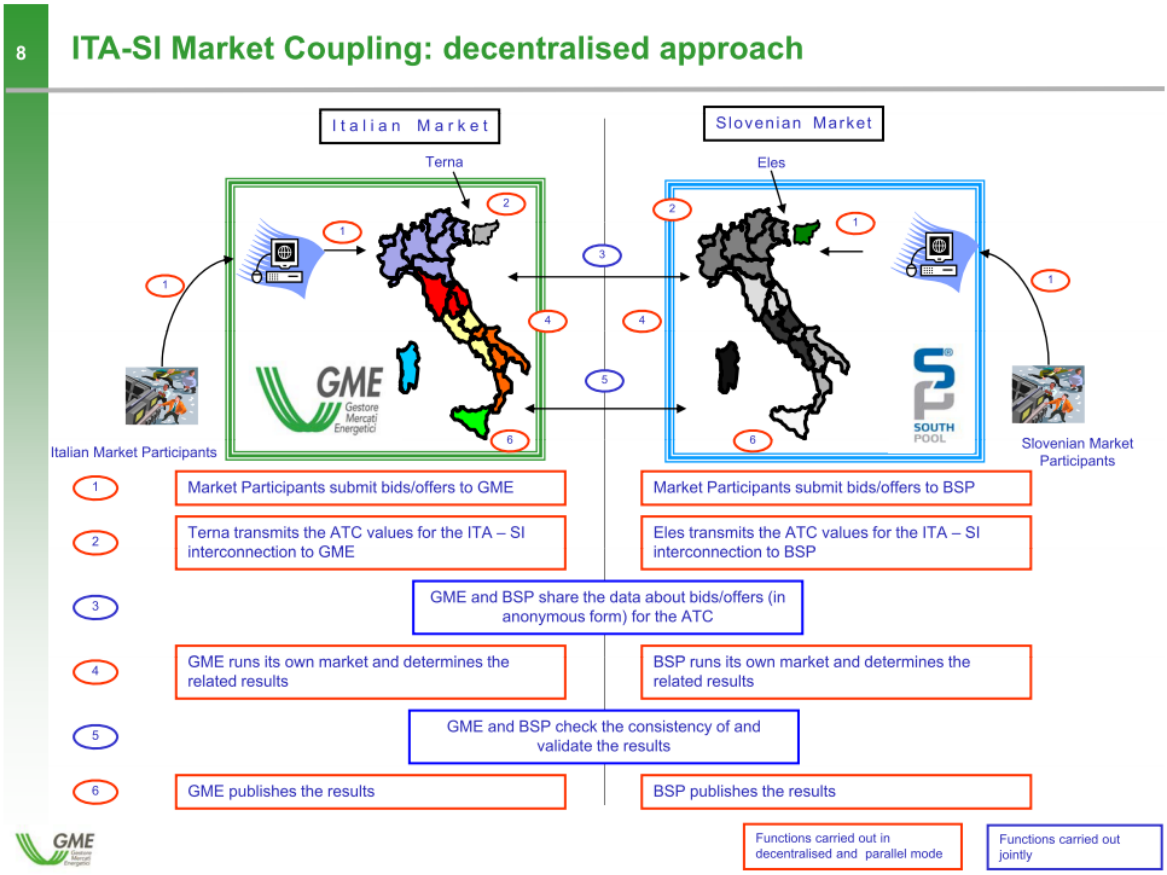
This option would allow Greece to be in charge of its own DAM and IDM (within the constraints of the Target Model), the connection to its participants and also be in control of the market development. Another positive aspect of this solution is that Greece in this case could offer this market coupling service on its other borders, and hence lead a regional solution. The neighbouring countries are in different stages of compliance with the Target Model, and to be able to offer this service would give a possibility to control these in a better way and take a leading role in the market integration in the region.

A key issue is how to have the coupled markets interacting with the internal market in Greece. The current Italy-Slovenia market coupling is a good example on how this might work allowing each of the countries to keep its control of the internal market as well as utilizing the interconnection capacity in the most optimal way. Figure 25 illustrates the current implementation of this market coupling between Italy and Slovenia.

This implementation is also done using the same decentralized approach that Pöyry recommended as part of the SEE WMO study and agreed by ECRB to be the model for the SEE region ('National control – regional co-operation').

These markets could be operated based on the same kind of market arrangements as in GB where the two power exchanges are put "on top" of the current market arrangements.

Figure 25 – Overview of approach for market coupling of Italy and Slovenia



Source - GME

7. ASSESSMENT PRINCIPLES AND NEXT STEPS

This Chapter considers the decision-making and assessment criteria that could be used in determining the next steps in the development of options for Greece to comply with the requirements of the European Electricity Target Model.

This Chapter is structured as follows:

- discussion of principles proposed by RAE for its review of Greek market design;
- high-level assessment of options against the proposed principles; and
- list of possible next steps in terms of evidence gathering to help in the assessment of which options for compliance merit being developed in more detail.

7.1 Proposed principles

In light of the introduction of the single electricity market by 2014, RAE is set to revisit the design of the Greek wholesale electricity market. As a first step, RAE is intending to examine the potential incompatibilities of the current market design model with the Target Model and other elements of the market that might not be incompatible, but have been proven ineffective.

The basic principles that RAE has set out for its review of the Greek market design are the following:

- creation of a stable and predictable market model, which will incorporate sufficient incentives to attract investment;
- environment that will facilitate healthy competition amongst the market participants, which will ultimately be beneficial to the end user;
- maintain the system's security and reliability (especially given the expected growth of RES penetration);
- market model compatible with the EPC (i.e. general model for European Price Coupling), but most importantly compatible with the model of Regional Market of the South-Central Europe (CSE); and
- minimisation of the adaptation cost and time to the Target Model.

7.1.1 Stable and predictable market model attracting investment

A major consideration in this area is the definition of stability – for example, it is possible to retain a stable market temporarily by deferring necessary changes until this is no longer possible, and a large and costly change is then required. However, this may be seen as less desirable or less stable than a series of incremental changes with a pre-determined transition path.

There are a number of external challenges to the development of a stable and predictable electricity market model that attracts investment, including:

- uncertainty about long-term environmental goals at EU level (e.g. renewable targets post-2020, carbon pricing);
- the suitability of the Target Model for a high renewables world (e.g. capacity mechanisms, consideration of reserve – these factors are both considered below under the minimisation of transition time and costs);
- economic outlook, both for the state and for companies; and

- growth (if any) in electricity demand, related to the economic situation but also to other factors such as the implementation of the Energy Efficiency Directive.

One of the other aspects of stability is the interaction between dispatch and the results of the wholesale market (forward, DAM, IDM). Major differences between these, particularly after the day ahead stage, can increase the balancing challenge for the TSO and market complexity (and hence reduce transparency) because they typically results in additional compensation payments, possible distortions to market results and/or weaker TSO control over dispatch (as discussed in Section 5.2.6 in relation to the Adaptation option). Therefore, to understand the implications for the transition to a compliant market design, it is important for RAE to analyse what causes difference between the wholesale markets and dispatch.

There are two main factors to consider. The first is changes in information (e.g. renewable output, demand, thermal availability, commodity prices) after the operation of the DAM (or the Pool where it is used for dispatch in the Adaptation option). This may be best addressed by greater emphasis on intraday trading (and/or rebidding) into the dispatch process to allow market participants to reveal this information to the TSO. One way to assess the importance of this factor would be to compare the difference in results between running the Dispatch Schedule with day ahead data and then with out-turn data (comparable to what is done to calculate the SIMP in the current Greek market arrangements). This assumes that the market participants have incentives to submit correct bids at the day ahead stage.

The second is differences between the scope of the dispatch decision and the scope of the market algorithms, for example in terms of the technical constraints considered. This issue is only going to be worsened by a move towards the Target Model, which will use a simpler algorithm than is currently used in the Greek market. One way to test the importance of this factor is to put the same information into both algorithms and compare the results. If this is an important factor this would favour a slower transition (e.g. to allow the price coupling algorithm to evolve) or even possibly seeing the Adaptation option as a possible end-point.

7.1.2 Facilitation of competition amongst market participants

The degree of competition and scope for wholesale market monitoring under different market arrangements should be an important consideration in designing the transition roadmap. Indeed, one of the stated purposes of the July 2012 Draft CACM NC[53] is to contribute to effective competition.

One of the main issues identified by RAE in its December 2011 Roadmap is the dominance of PPC on both the generation and retail side. A strong incumbent with a diverse portfolio such as PPC's, owning lignite, hydro, gas-fired generation and renewables, can discourage other players to enter the market, or can lead to exit from the market, especially in periods of low demand (such as the current situation).

However, one of the concerns of moving away from the existing Greek market design is the potential removal of a number of market power mitigation measures. Some of these measures though have introduced their own distortions.

On one hand, the transitional measures, such as the Cost Recovery Mechanism and the Transitional Capacity Adequacy Mechanism, have been the main reason for new players

[53] Paragraph 10.

entering the market as it has enabled them to hedge their income. On the other hand, these generators are no longer incentivised to compete against each other in the market because the two measures (in their current form) have started to create distortions to the market. The Cost Recovery Mechanism in combination with the zero price floor for the first 30% of capacity allows generating units to bid part of their capacity with a zero price. They know that their electricity income however will be guaranteed to be at least their variable cost inflated by 10%. This could lead to inefficient outcomes, with higher costs for Greek consumers.

Therefore, RAE may wish to consider how best to define and measure competition within the context of a more integrated electricity market. For example, this could help to define measures for identifying when an effective regional market has been implemented, which could allow the lifting of market power mitigation measures even at relatively high national market shares.

7.1.3 Maintain system security and reliability

The Target Model is based on the premise that security of supply is enhanced by allowing market participants to balance their position through trading close to real time. At the same time, the Target Model is associated with a weakening of the TSO control over dispatch in a number of markets, such as Greece, as well as moving to market scheduling solutions less constrained by physical network factors. Therefore, RAE may wish to gather evidence on the relative roles that the market and the TSO can play in delivering security of supply.

7.1.4 Compatible with developments in Europe, especially CSE market

Based on high-level design, these options for market coupling with Italy could work with all of the options for Target Model compliance (discussed in Chapter 5). However, synergies and conflicts may appear as the options are taken forward into a detailed design phase.

The electricity market designs in the countries neighbouring Greece are themselves evolving, with all of them signed up to implementing greater market integration. However, these developments will proceed at different speeds. For example, ENTSO-E has recently announced an extension (to autumn 2013) for the commercial phase of the trial synchronous operation of the Turkish power system with Continental Europe[54]. This commercial phase allows for limited capacity allocation for commercial electricity exchanges between Turkey and Greece, and Bulgaria, according to procedures mutually agreed by the three countries, and in line with EU rules and ENTSO-E procedures.

Some of the options outlined offer Greece to take a more active role in leading regional market integration. This however may incur greater costs, and delay the implementation of market coupling in Greece owing to greater investment and systems and the need to wait for developments in neighbouring countries.

7.1.5 Minimization of the adaptation cost and time to the Target Model

A key consideration in the definition of an appropriate transition roadmap will be the cost and time needed to implement any system changes. However, there should not be an excessive emphasis on the direct costs of system changes because they are visible. Wider and ongoing costs and benefits (e.g. more effective competition) would also be part

54 'ENTSO-E News', ENTSO-E, 12 September 2012.

of a comprehensive assessment, although we acknowledge that these more intangible factors can be harder to quantify with a wider range of possible values.

One of the challenges for defining the transition roadmap to Target Model compliance is the fact that the Target Model is itself evolving over time. Three examples are described below:

- interaction with capacity mechanisms;
- time allowed for implementation of the EB FG requirements; and
- co-optimisation of energy and reserve.

Although not consistent with the spirit of the Target Model (particularly when not developed on a coordinate basis), capacity mechanisms are now being considered in most Western European markets largely as a response to the challenges of intermittency. Therefore, there is a risk for Greece that it could move away from a capacity mechanism to fit better with a Target Model, which may evolve to accommodate capacity mechanisms.

The draft EB FG allows for 3 years for countries to move to greater harmonisation of balancing activities, and 7 years for a move to the long-term solution of a common merit order for balancing across Europe. Therefore, any transition roadmap for Greece should consider whether it can defer decisions on balancing arrangements until the completion of the Balancing NCs, which will be in 2014 at the earliest.

At the moment, the price coupling algorithm does not allow for the co-optimisation of energy and reserve (unlike the existing Greek DAS). As discussed in Section 3.2.6 of this report, one of the long-term solutions for pricing intraday capacity may involve the co-optimisation of reserve and energy. In that case, retention of co-optimisation by Greece may ultimately reduce compliance costs (say compared to moving away from co-optimisation, and then reintroducing it).

On the other hand, market coupling initiatives continue to develop, as shown by the NWE project and the Price Coupling of the Regions project, involving six power exchanges, (APX-Endex, Belpex, EPEX Spot, GME, Nord Pool Spot, and OMEL). Therefore, earlier (and more active) engagement in the market coupling process could give Greek stakeholders more opportunity (where it still exists) to influence the detailed design.

7.2 High-level assessment of options against proposed principles

Table 18 summarises a high-level assessment we have carried out of the possible advantages and disadvantages of each option against these principles. This fits with the scope of the current study, which is designed to provide some high-level options.

Table 18 – High-level assessment of advantages and disadvantages

Criteria		Adaptation option	NWE option	Hybrid option
Stable and predictable market model	Positives (+)	▪ Ability to anticipate (possible) further changes to Target Model (e.g. co-optimisation, capacity mechanisms)	▪ (Nominally) a clear legally compliant endpoint; ▪ Provides allies for common resistance to further change	▪ (Nominally) a clear legally compliant endpoint; ▪ Provides allies for common resistance to further change
	Negatives (-)	▪ Storing up more frequent and/or bigger changes for future, particularly if question marks over legal compliance	▪ Further changes required if Target Model continues to evolve	▪ Further changes required if Target Model continues to evolve
Competition	Positives (+)	▪ Gross mandatory pool is route to market for new entrants; ▪ Market power mitigation measures built into market arrangements; ▪ Transparency of reference price from pool	▪ **Arrangements well-understood by foreign players**; ▪ Robustness of DAM results for reference price	▪ **Retention of a (voluntary) pool should help to focus liquidity (providing route to market)**; ▪ May allow gradual removal of market power mitigation measures
	Negatives (-)	▪ Low liquidity (if any) in DAM and IDM may limit 'import' of competitive pressures; ▪ Limited international understanding of specific Greek arrangements	▪ **May need additional (targeted) market power mitigation measures**; ▪ Uncertainty about accessibility of market for new entrants	▪ If Pool arrangements are complex, it may reduce accessibility for foreign players
Security and reliability	Positives (+)	▪ TSOs retain large amount of control	▪ **Interconnection flows may be more efficient (and responsive intraday)**	▪ DAM collects together information on all contracted positions at the day-ahead stage
	Negatives (-)	▪ **Uncertain how schedule and dispatch will interact in practice**	▪ Need new balancing tools (no co-optimisation); ▪ Reliance on intraday adjustments in market	▪ Need new balancing tools (no co-optimisation)
Compatible with CSE (and EPC)	Positives (+)	▪ None (risk of non-compliance)	▪ **Compatible with spirit and letter of EPC**	▪ **Similar to Spanish arrangements, and bid format should be accommodated by the PCR algorithm**
	Negatives (-)	▪ **Use of coupling as adjustment markets not in spirit of CSE and EPC;** ▪ **Possibility of not being fully compliant with detailed rules**	▪ Closer to NWE than CSE	▪ None (fully compatible with CSE)
Minimise adaption time and cost	Positives (+)	▪ **Least change from current arrangements**	▪ Scope to use systems already established in other markets	▪ Range of bids available in DAM may help market players become more comfortable with new arrangements
	Negatives (-)	▪ **TSO needs to update dispatch and 'imbalance settlement' arrangements to take coupling results into accounts**; ▪ Market participants need to have separate systems in place for Greek pool and for coupling	▪ **Major change to current arrangements for all market participants**	▪ **Still need for potentially significant adaption of market features with impact on systems for all market participants**

7.2.1 Summary assessment of the Adaptation option – compliance is questionable

Although this option represents minimum change, which should reduce the time and cost of implementation, it raises a number of major implementation and compliance changes that it could be useful to consider in more detail (including expert legal review) as part of the RAE market design project. These include:

- **Whether or not treating the DAM as an adjustment market would be deemed to be compliant with the spirit of the Target Model.**
- **Interaction between central dispatch** (as determined by the bids into the gross mandatory pool) **and the trading in the DAM and IDM** which will be key in understanding implications for the TSO (in balancing the system) and Market Participants.

7.2.2 Summary assessment of the NWE option – major change for Greece

This option represents a major change from the current arrangements, which is likely to require significant investment in time and costs for changing central systems and market participants' systems. By removing many of the key features of the current Greek arrangements (in particular the gross mandatory pool), there is a need for the development of new balancing tools to help the TSO deliver secure supplies. The option also raises questions (particularly in the initial stages of implementation) about the need about the need for new (targeted) market power mitigation measures.

On the other hand, this option is strongly in line with European requirements meaning that long-term compliance with the Target Model should not be an issue (even if the speed of transition is challenging). It should improve external competitive pressures on the Greek market, either through more efficient interconnector flows or through moving to arrangements that are well-understood by foreign players.

7.2.3 Summary assessment of the Hybrid option – softer transition path with higher cost

The Hybrid option similarly represents major change from the current arrangements, with the abolition of the gross mandatory pool in its current form. New ancillary services and balancing markets will need to be introduced (as in the NWE option).

However, the use of a (voluntary) pool for the DAM (even if is in a different form to the current Greek pool) may help to ease the transition to the new arrangements. Greek market players may feel more comfortable about their risk exposure under complex bid formats and conditions (rather than the block bids of the power exchange). The prohibition on withholding physical capacity from the DAM may also help address some of the issues around market power mitigation measures (although may reduce liquidity in the intraday market).

This option should also be compliant with the developments in the CSE region (particularly Spain), as well as the Target Model more generally. There is a risk though that using a pool for the DAM may allow greater scope for direct political interference in market scheduling (than would be possible under a NWE power exchange). One example of this from Spain is the insertion of the subsidised coal plants into the schedule after the daily price has been fixed.

7.3 Possible next steps in evidence-gathering

Our detailed discussion of each of the proposed principles and our high-level assessment highlight a number of areas in which further evidence may be useful to RAE in deciding which options to develop in more detail. These areas include:

- studies of the main causes of the difference between dispatch and the traded markets, particularly at the day ahead stage to ascertain the importance of co-optimisation, the bid structures used within the gross mandatory pool and re-bidding opportunities in Intraday trading;
- the advantages and disadvantages of more (or less) centralised control over dispatch;
- circumstances under which regional market integration would provide effective competition for the Greek incumbent;
- indirect costs and benefits of different market models, as well as tangible costs, such as system changes;
- further investigation into the detailed legal requirements for compliance (particularly as the Network Codes move closer to finalisation); and
- more detailed review of the proposed developments in neighbouring countries.

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ANNEX A – PRICE AND VOLUME COUPLING

Market coupling is the process of joining together different market areas with the purpose of using implicit auctions to determine interconnector flows. The main benefits of implicit auctions include:

- more efficient use of interconnection capacity;
- more efficient price discovery through greater liquidity in Day Ahead trading; and
- reduced need for wheeling of bilateral contracts in which the generator and the customer are not in countries that are not directly interconnector (e.g. as would happen if an Greek generator was able to strike a bilateral contract with a customer in Austria).

There are two broad types of market coupling arrangements – price coupling, and volume coupling (which can itself be described as either 'tight' or 'loose').

A.1 Price coupling

Price coupling is based on a single algorithm that uses bid/offer information from each market and the available cross border capacities. The algorithm jointly establishes prices, generation volumes and interconnector flows for each coupled market and takes into consideration all bids/offers from all markets.

An example of Day Ahead price coupling is the Central Western European Market Coupling (CWE), which includes Belgium, the Netherlands, France, Germany and Luxembourg. This means that Day Ahead market prices in each of these countries are determined in parallel to those in other CWE countries, according to an agreed algorithm[55].

Market participants submit their purchase or sales orders by midday (12.00pm CET) for each hour of the following day (starting at midnight CET). All potential trades are then aggregated by hourly periods and ranked according to price. For each hour, the intersection of the aggregated supply and the aggregated demand curve determines the market results (i.e. the market clearing price and the market clearing volume).

After this fixing is performed, the market results are made available to participants. When there is insufficient interconnection capacity to ensure price equality across region, then markets decouple and more than one price emerges. Contracts are then created which require participants in each country to deliver to or to withdraw from the network they are connected to the volume of electricity in accordance with their contracts.

A.2 Volume coupling

Under volume coupling arrangements, the coupling system uses a single algorithm to determine the flows across the interconnectors between the underlying regions/markets, based on anonymous bid/offer information from each market. The algorithm partly replicates the matching rules of each coupled market.

However, the **Day Ahead** price in each market is still determined separately by the local power exchange which uses the generated cross-border volumes to locally determine their bidding area(s) prices and volumes. As a consequence, there is the potential that

55 http://www.apxendex.com/uploads/tx_abdownloads/files/COSMOS_public_description.pdf

should the out-turn prices deviate from those estimated in the market coupling process, the interconnector flows may not be consistent with the resulting Day Ahead prices.

The difference between tight and loose volume coupling relates to the degree of replication of local market rules and the level of indicative bid/offer information used. Loose volume coupling allows the coupling of two markets which have significant differences in local rules, without the need for major and substantial changes to either market.

Under loose volume coupling, the difference between the market design used to determine the interconnector flows and used to determine the market prices can frequently lead to cases whereby the interconnector flows are not always consistent with final prices.

This was seen in the initial difficulties faced by the loose volume coupling between Denmark and Germany. Discrepancies between the market coupler's results compared with the results from the individual power exchanges resulted from the combination of the loose volume coupling methodology with an illiquid market in Denmark. The issues were resolved by the introduction of tighter volume coupling arrangements, which better reflect the market rules and algorithms of the coupled markets.

ANNEX B – DAY AHEAD MARKET COUPLING INITIATIVES

There are currently two industry-led initiatives to deliver Day Ahead price coupling by the end of 2012:

- the TSO-driven project for full Day Ahead price coupling across NWE (covering CWE, Nordic markets and BETTA); and
- the price-exchange led project, the Price Coupling of the Regions (PCR), which includes NWE as well as Iberia and Italy.

Although neither would cover Greece, they provide a useful guide to the arrangements that may be expected to be put in place in the future.

Both initiatives expect to have an enduring market coupling solution in place by the end of 2012. They share a number of common features, including gate closure timing and definition of stakeholder roles (as summarised in Figure 26):

- **Market players;**
  - submit bids (simple or block) to local power exchange on voluntary basis;
  - receive firm prices and quantities from local power exchange;
- **Local power exchanges;**
  - gather bids and offers (simple and block) for local market[56] (with an obvious need to ensure liquidity);
  - turn simple bids into a net export curve (NEC) [57] for sending to central market coupler;
  - pass (anonymised) block bids directly to central coupler;
  - are responsible for dealing with local legal, regulatory and governance issues;
- **Central market coupler;**
  - gathers NEC and block bids from local exchanges[58];
  - collects available transfer capacity (ATC) from TSOs to determine interconnection capacity available for use by the central coupler in the Day Ahead market;
  - provides local power exchanges with results on which bids and offers have been accepted;
- **TSOs;**
  - provide central market coupler with all ATC at Day Ahead (i.e. total available capacity minus any flows nominated by long-term capacity holders before the Day Ahead stage); and

---

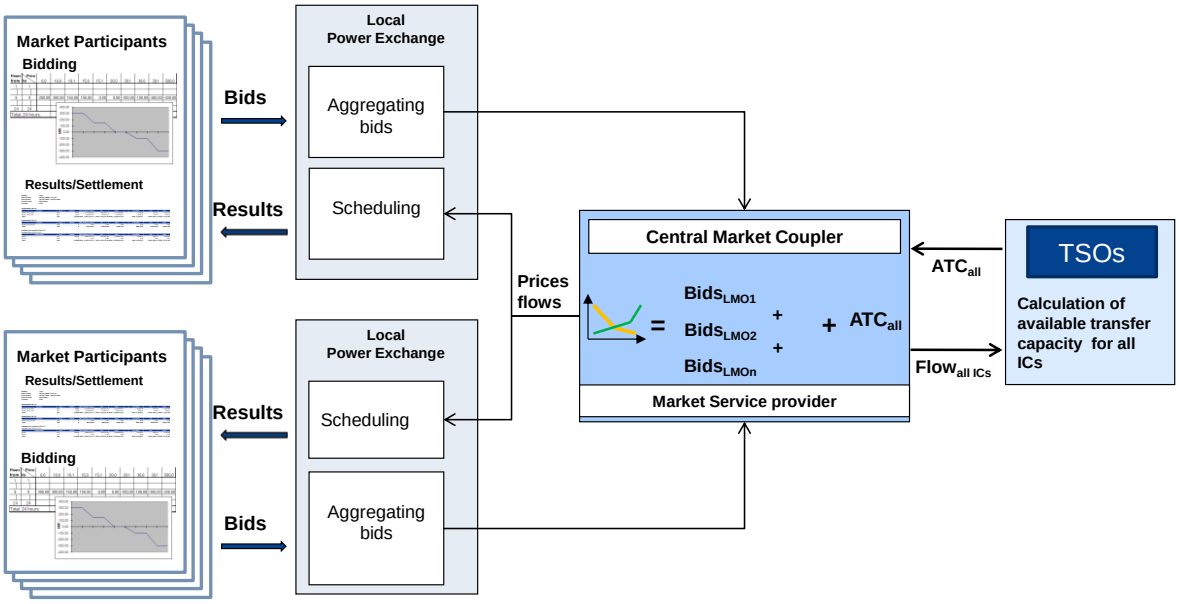
56 It is possible to have more than one local exchange for a market, as shown by BETTA where there are currently two power exchanges operating.

57 A net export curve for hour *h* gives the potential net export (based on hourly orders) from a market at each possible market price. This is a specific form of aggregated bids and offers curve. In the rest of this report, the term NEC is used to denote aggregated bids and offer curve.

58 This process requires the definition of common data exchange parameters and common rules on acceptable bid parameters.

– facilitate flows.

Figure 26 – Overview of market coupling processes



There have been some differences between the initiatives but these relate more to implementation than to high-level design:

- **leadership** – whether it is the TSOs or the power exchanges;
- **geographical coverage** – the PCR initiative extends to include Italy and Spain; and
- **governance** of the central market coupler – whether it is a regulated monopoly function or shared between the power exchanges (on rotation).

ANNEX C – ALGORITHM DESIGN UNDER THE PCR FORMATS

The PCR (Price Coupling of Regions) is a project by the 6 biggest Power Exchanges in Europe to develop a common price algorithm to be used as a single price coupling mechanism across Europe. The power exchanges involved are APX/Endex, Belpex, Epex Spot, GME, OMEL and Nord Pool Spot.

There are three aspects to the design of the algorithm currently being developed by the PCR initiative[59]:

- bid and order formats;
- price properties; and
- network properties.

C.1 Possible bid and order formats

The bid and order formats currently under consideration in the PCR project are:

- hourly;
  - stepwise;
  - linear interpolate;
- fill or kill block;
  - profile block;
  - linked block;
- minimum income (or payment) conditions;
- load gradients constraint – i.e. way of dynamically shifting start of a bid;
- schedule stop constraint, which allows the generator to stop supplying energy in at most 3 hours if a Minimum Income condition is not fulfilled;
- indivisibility constraint, which we understand is seldom used in practice; and
- merit order priority.

C.2 Price properties

The price properties effectively describe the objectives taken into account in the algorithm:

- welfare optimisation
- Italian PUN, whereby there is a single national price for demand but zonal prices for generation;
- price range and precision; and
- curtailment rules.

59 Taken from Appendix II (Algorithm requirements and current situation) to the 'PCR update to the 5TH SG meeting. Deliverable I.2 Day-Ahead Market Coupling. Price Coupling. Update on Single Algorithm'.

C.3 Network properties

These are the 'technical' constraints taken into account by the proposed algorithm:

- balance constraints;
- interconnection capacity constraints; and
- ramping constraints – interconnector flows and net positions.

ANNEX D – POSSIBLE ROLES AND RESPONSIBILITIES

We have been asked to provide a high level description of the key roles of the various stakeholders in a new market framework and the implications this will have on the current setup. In doing so, we have drawn on the descriptions in the July 2012 draft of the CACM NC, and our SEE WMO study.

The operation of a power market closely aligned with the Target Model requires close cooperation between two key organisations – the TSO and the Market Operator. These two organisations will have clearly defined roles and responsibilities along with:

- power industry regulators;
- market participants (power generators, power consumers, traders); and
- DSOs.

The roles and responsibilities for each of these are described below. In addition, Annex B provides more details on the roles and responsibilities of different stakeholders in two Day Ahead price coupling initiatives.

D.1 Roles and responsibilities of the TSO

The TSOs play a very important role in deregulated power markets. The TSOs' responsibility to operate, maintain the reliability and quality of the power supply will always set the daily framework for the market operations. As a monopoly activity, the performance and business processes of the TSO will be closely monitored by the regulatory bodies.

Article 12 of the July 2012 draft CACM NC assigns the following functions to the TSO:

- System Operator;
- Scheduled Exchange Calculator;
- Market Information Aggregator;
- Coordinated Capacity Calculator;
- European Merging Function (in relation to the creation of the Common Grid Model)
- Shipping Agent; and
- Congestion Income Distributor.

In the SEE WMO study, we defined the following responsibilities for the TSO that can be seen as relevant for the operation of the Target Model (in say the NWE option), highlighting in bold areas representing significant change from the current function of the TSO:

- provide routines to maintain short term power reserves;
- manage real time operations and handle unpredictable imbalances and unexpected events;
- **operator of the Balancing market, Ancillary Services market as well as other required markets/mechanism to ensure an efficient balance management;**
- cooperate with TSOs of interconnected grids;
- manage transmission capacity on the neighbouring interconnections; and

- manage imbalance settlement and billing.

In the Adaptation option, the role of the TSO would remain largely unaffected. As well as the activities listed above, the TSO would remain responsible for the operation of the Capacity Adequacy Mechanism (as at present).

In our SEE WMO study, we also identified ownership of the Day Ahead and Intraday Market Operator as being a TSO responsibility. This is compatible with the Target Model but is not an essential requirement for the NWE option.

In the first few years of operations after the implementation of a market platform, the trade of physical products will be the focal point. These mostly short term products, especially Day Ahead, cross-border capacities for DAM and balancing power, are crucial for the TSOs' management of security supply issues. It therefore may be advisable that the TSO has a strong relationship with the local market operator, which could include ownership. In the case services are bought from an existing provider; it may be advisable for the TSOs to be the contract counterpart either directly or via its local market operator.

At a later stage when the launch of financial electricity contracts takes place, it may be advantageous to introduce additional owners in the regional service provider, e.g. banks and other financial institutions.

Finally, we list the other TSO responsibilities we identified in our SEE WMO study that are not directly applicable to a discussion of the impacts of the Target Model:

- determine rules and requirements for supply quality and security;
- propose transmission tariffs for the main grid;
- operate and maintain the grid within its defined area;
- collect and report metered values; and
- purchase electricity to cover grid losses.

In addition, the TSO may also be involved in facilitating renewable support schemes.

D.2 Roles and responsibilities of the Day Ahead and Intraday Market Operator

The Market Operator usually has a license or cooperation agreement to operate the DAM/IDM under the framework set by the regulator. A market operator should always facilitate trade, the transparent handling of price sensitive information, support market competition and build market liquidity.

Article 13 of the July 2012 draft CACM NC assigns the following functions to the Nominated Electricity Market Operator (NEMO):

- Nominated Electricity Market Operator;
- Market Coupling Operator; and
- Central Counter Party.

The core responsibilities for the Market Operator that we identified in the SEE WMO study are to:

- operate a DAM based on an implicit auction and the market splitting (or coupling) principle;

- provide reference price(s) for energy;
- use the price mechanisms to alleviate grid congestion through optimal use of available transmission capacity in the case of congestion;
- operate an IDM;
- act as a reliable counterpart; and
- report to TSOs, participants and to the public required information and data

It is possible that the Market Operator could also provide services for other related power markets.

D.3 Regulator

Regulators determine guidelines and bylaws for the regulation of monopolies within the power market, with the Third Energy Package requiring the designation of an independent regulator. Under the NWE option, regulatory authorities' responsibility for guidelines, standards and regulations of the local power system and the power market remains unchanged.

In the SEE WMO study, we listed the following issues as examples of areas covered by the regulator:

- market design and market rules;
- harmonisation, definition and approval of guidelines for:
  - power system operation;
  - metering;
  - grid tariffs etc.;
- responsible for licensing of TSO, market operator and other required licensees;
- monitoring the costs and performance of monopolies such as the TSO (and possibly the Market Operator);
- provide incentives for eligible customers to exercise eligibility;
- responsibility of Market Monitoring and Market Surveillance both on a local and regional level; and
- create monitoring regime for the market(s) operated by TSO and Market Operator (the market surveillance can be outsourced as a department of the TSO and/or Market Operator).

D.4 DSOs

The DSOs will be responsible for measurement within each DSOs distribution area. Metering values for wholesale market participants connected to the DSOs grid have to be sent to the TSO for balance settlement.

D.5 Market Participants

Market Participants are legal entities that operate in the wholesale and/or retail markets. They can play multiple roles consisting of one or a combination of the following: generator, consumer (eligible and large industries), trader or retailer.

Large dominant producers ('incumbent producers') will be important participants in the market. They will normally secure their position and further develop their competitive ability inter regionally. An important prerequisite is full competition with respect to allocation procedures of cross-border capacities so that both incumbent and new entrants in generation have equal access to transmission.

ANNEX E – IMBALANCE SETTLEMENT UNDER THE CURRENT GREEK MARKET ARRANGEMENTS

As discussed in the main body of the report, the activation of balancing energy is done by the TSO throughout the dispatch process. However, the amount associated with the compensation or penalisation of any deviation from the DAS is based on resolving the same cost-minimisation algorithm used in the DAS ex-post (taking account of actual demand, RES production and plant availability). The result of this process is the System Imbalance Marginal Price (SIMP).

The Imbalance Settlement provides both compensation for instructed deviations and penalties for uninstructed deviations. Therefore, the Imbalance Settlement cannot be considered as a 'pure' Balancing Mechanism as it also includes an 'imbalanced position penalisation' component.

The general idea behind the Imbalance Settlement, which is conducted after the day, is the reallocation of cash flows from participants that were responsible for potential imbalances to participants that helped out in the balancing of the system. The compensation/penalties that arise though the Imbalance Settlement take account of the position of the generating unit (or load) in the DAS, the dispatch instruction and the final metered volume.

All the possible charges/compensations depending on the position of a market participant in the DAS (DASQ), the dispatch instruction (INST) and the metered volume (MQ) are summarised in Figure 27. Please note that the all values in Figure 27 are algebraic. This implies a payment when the value is positive and a charge when the value is positive.

Figure 27 – Compensation and charges under the Imbalance Settlement

Upwards instruction	
MQ< DASQ	**MQ >= DASQ**
(MQ- DASQ) * SIMP	(min(MQ;INST) - DASQ) * SIMP
Downwards instruction	
MQ< INST	**MQ>= INST**
(DASQ- INST) * Cost + (MQ- INST) * SIMP	(DASQ- INST) * Cost

We have attempted to distinguish the two components that are included in the Imbalance Settlement (meaning the component relating to instructed deviation and the component of an uninstructed deviation or an imbalanced position). Figure 28 summarises the compensation/charges.

The component under instructed deviation would be the component relating to provision of balancing services (in addition to this a unit receives the payments relating to reserve provision). In the case where a market participant is instructed to increase its output, the market participant will receive a payment for the additional output (when compared to the DAS) at a price equal to the SIMP. When a market participant is instructed to reduce its output, then he has to pay back the cost associated with reduced output when compared to the DAS quantity, hence keeping the inframarginal rent from the DAS.

The component under imbalanced position refers to the charges (if any) for not following a dispatch instruction – hence what we would call an imbalance price. Figure 28 details all possible combination that can arise for a market participant.

Figure 28 – Breakdown of the instructed deviation compensation and imbalanced position charges

Instructed deviation	
Upwards	Receive SIMP
Downwards	Pay back cost

Imbalanced position		
	MQ< INST	MQ>= INST
Upwards	Pay back SIMP	0
Downwards	Pay back SIMP	0

Example 1 (Dispatch instruction above the DAS quantity and metered volume below DAS quantity)

In this example, a generating unit, that was scheduled to produce 150MW in the DAS, receives a final dispatch instruction of 170MW[60]. However, its metered volume is 120MW, meaning that not only did it not increase its output, but it was also below the original DAS scheduled quantity.

The generating unit will be paid for the 150MW at the cleared SMP (in the DAS) and will be charged for the (150-120) = 30MW at the SIMP. Given that the instruction was for the unit to increase its output it is expected that the system was short (compared to the DAS) and therefore the SIMP should be higher than the SMP. This means that the generating unit was overall penalised for its imbalanced position.

Under the breakdown that we have introduced in Figure 28 we would have the following:

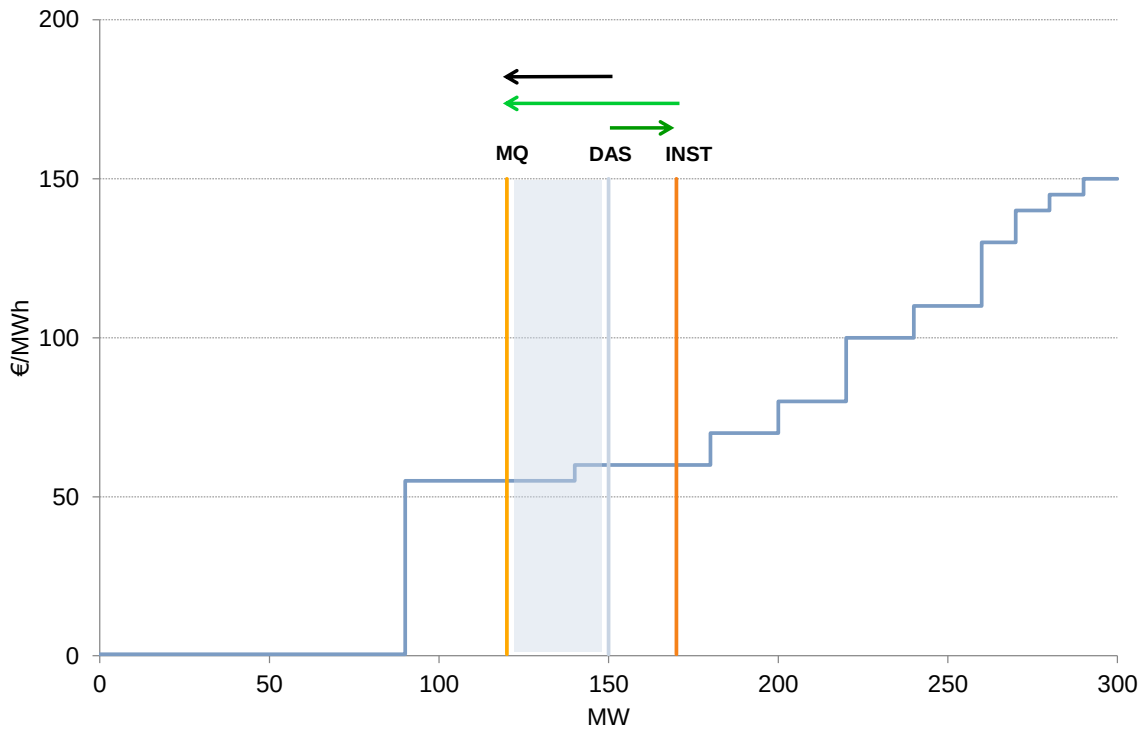
- The unit receives a payment for the 150MW based on the SMP;
- The unit receives a payment for the (170-150) = 20MW based on the SIMP (as per the dispatch instruction), which would correspond to the dark green arrow in Figure 29; and

60 For simplicity we are going to assume that the tolerance limit is zero.

- The unit has to pay back for (170-120) = 50MW that arise from the imbalanced position when compared to the dispatch instruction based on the SIMP, which corresponds to the light green arrow in Figure 29.

The net effect is that the unit pays back 30MW (black arrow in Figure 29) at the SIMP, which is what the Imbalance Settlement dictates. We have effectively assumed two virtual cash flows that do not occur in reality and have a zero net effect, meaning that the unit gets paid for the 20MW that it should have provided as per the dispatch instruction and gets charged for the same amount.

Figure 29 – Imbalance Settlement example



Example 2 (Dispatch instruction above the DAS quantity and metered volume above the dispatch instruction)

In this example, a generating unit that was scheduled to produce 120MW in the DAS, receives a final dispatch instruction of 170MW. However, its metered volume is 180MW, meaning that it increased its output beyond the dispatch instruction.

The generating unit will be paid for the 150MW at the cleared SMP (in the DAS) and will receive an additional payment for the 20MW at the SIMP. However, the unit will not receive any payment for the additional 10MW above its dispatch instruction.

Following the same principle as in the previous example and working our way through Figure 28 we end up with the same result.

The same principle can be applied to all possible combinations of metered volume, DAS position and dispatch instruction.

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