METIS Studies

Study S12

Assessing Market Design Options in 2030

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1. ABBREVIATIONS AND DEFINITIONS

1.1. ABBREVIATIONS

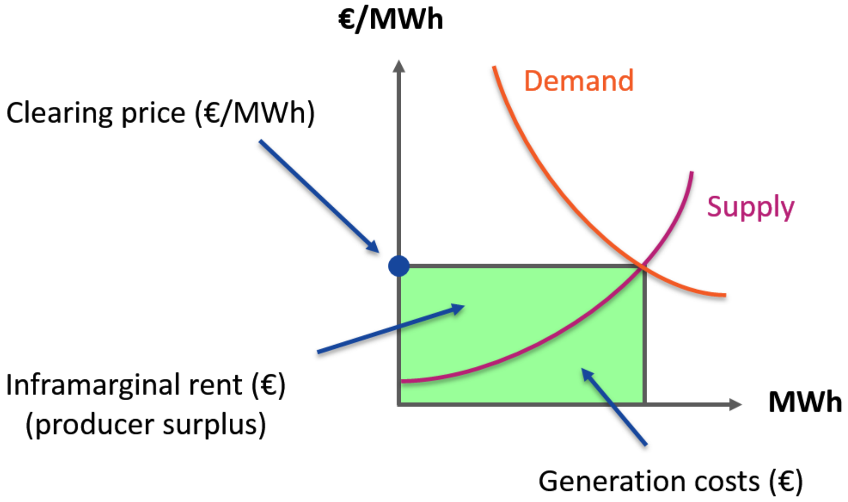
Abbreviation	Definition
BSP	Balancing Service Provider
BRP	Balancing Responsible Party
DR	Demand Response
CMOL	Common Merit Order List
FCR	Frequency Containment Reserves
FRR	Frequency Restoration Reserves (aFRR and mFRR)
IA	Impact Assessment
KPI	Key Performance Indicator
MDI	Market Design Initiative
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
RES	Renewable Energy System
RR	Replacement Reserves
RSC	Regional Security Coordinator
TSO	Transmission System Operator

1.2. DEFINITIONS

Concept	Definition
Active Power Reserves	Balancing reserves available for maintaining the frequency. This term is to be understood as the sum of FCR reserves and aFRR reserves.
Balancing	All actions and processes, on all timelines, through which TSOs ensure, in a continuous way, the maintenance of system frequency within a predefined stability range and compliance with the amount of reserves needed with respect to the required quality. Imbalances can occur due to a number of reasons (see Imbalances).
Balancing Capacity	TSOs may hedge against the risk of not having enough Balancing Energy bids by BSPs in real-time by procuring Balancing Capacity ahead of real-time. Providers of Balancing Capacity have to inject or withdraw Balancing Energy at the TSO’s request for the duration of the contract period.
Balancing Energy	Energy, either injected in or withdrawn from the electricity grid in real-time, used by TSOs to compensate for unforeseen imbalances and to guarantee the stability of the power system.

Balance Responsible Party (BRP)	Market participant or its chosen representative responsible for its imbalances.
Balancing Service Provider (BSP)	Market participant with reserve-providing units or reserve-providing groups able to provide balancing services to TSOs.
Common merit order list	List of Balancing Energy Bids sorted in order of their bid prices used for the activation of balancing energy bids
Downwards regulation	Action required when the electricity system is long (i.e. the frequency is higher than its nominal value)
Frequency Containment Reserves (FCR)	Active power reserves available to contain system frequency after the occurrence of an imbalance
Frequency Restoration Reserves (FRR)	Active power reserves available to restore system frequency to the nominal frequency and, for a synchronous area consisting of more than one LFC area, to restore power balance to the scheduled value
Imbalances	Energy volume calculated for a Balance Responsible Party and representing the difference between the allocated volume attributed to that Balance Responsible Party and the final position of that Balance Responsible Party, including any imbalance adjustment applied to that Balance Responsible Party, within a given imbalance settlement period. At intraday gate closure time the generation planning is balanced. Imbalances can be caused by noise, 5-minute gradient, forecast errors, and outages that happen between the intraday gate closure time and real-time.
Load payment	The load payment is the total payment made by the public for the provision of electricity. It is computed as the product of the marginal cost of electricity and the demand time series. Note that this computation assumes a pay-as-clear market clearing process. **Figure 1** illustrates this definition in a simple case. Load payment in this case is given by the sum of the production cost and the inframarginal rent (producer surplus).
Pay-as-clear	Market clearing practice in which all selected offers receive the amount offered by the highest selected offer
Reserve Capacity	Amount of FCR, FRR or RR that needs to be available to the TSO
Replacement Reserves (RR)	Active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including operating reserves
Upwards regulation	Action required when the electricity system is short (i.e. the frequency is lower than its nominal value)

Figure 1 - Load payment – Illustration



The figure above illustrates the definition of load payment (shown in light green) when using pay-as-clear practices. Load payment is defined as the payment made by the public for the provision of electricity. It consists of two parts (congestion rents are disregarded in this discussion): the generation costs and the inframarginal rent (or producer surplus). When using pay-as-clear practices, each generator receives the clearing price for each MWh of electricity it produces. The total cost to the public therefore not only covers the generation costs, but also provides a surplus to those generators which have generation costs that are lower than the market clearing price (i.e. to all generators but the marginal unit).

The load payment is computed as the sum over time-steps (8760 hourly time-steps per year) of the product of the electricity clearing price and the electricity demand.

1.3. METIS CONFIGURATION

The configuration of the METIS model used to evaluate the impacts of the MDI policy measures is summarised in **Table 1**.

Table 1 - METIS Configuration

METIS Configuration	
Version	METIS v1.1
Modules	Power system and power market modules
Scenario	METIS EuCo27
Time resolution	Hourly (8760 consecutive time-steps per year)
Spatial granularity	Member State
Bidding strategy	Marginal cost bidding

2. EXECUTIVE SUMMARY

Context

The European Commission's Energy Union strategy aims at providing Europe with a secure, sustainable and competitive energy. In order to cost-efficiently reach its climate and energy goals, Europe has to ensure that its energy systems embed a high level of flexibility to easily integrate large shares of variable electricity, that its energy markets are well-interconnected, and that the demand-side is encouraged to actively participate in the functioning of short-term markets. Moreover, the European Commission actively encourages Member States (MSs) to cooperate so as to better exploit the synergies between their energy systems.

The current market arrangements should therefore be revised in order to increase the flexibility of the electricity system so as to allow it to host high shares of variable electricity generation and to better exploit resources. The European Commission will introduce new legislation (Market Design Initiative) to this effect.

The policy measures considered by the European Commission have been grouped in coherent policy packages having specific orientations:

- Reducing the current inflexibility of the power system
- Better interconnecting short-term markets
- Pulling distributed flexible resources into the market
- Fully integrating the EU markets

Objectives of the study

This study was commissioned by the European Commission to examine the benefits of a number of policy options (packages of measures) addressing the four orientations outlined above. The aim of this report is to present the benefits associated with each of these options, which have been assessed by using the METIS model, which is developed by Artelys and its partners for the European Commission.

The main characteristics of the market design options investigated in this report are shown below:

MDI option	Description
Sub-option 1a	This option aims at **reducing the current inflexibility** of the power system. It foresees the removal of most of the technology-specific rules. The main policy measures studied in this report are: - Removal of priority dispatch and must-take rules - All market participants become balance responsible - Removal of intraday must-run arrangements for coal and lignite units
Sub-option 1b	The policy measures included in this option focus on **increasing the interconnection between short-term markets**. The main policy measures studied in this report are: - Reserves are dimensioned and procured at a regional level instead of the Member State level - All suboptimal reserve procurement practices are abandoned - Intraday markets are coupled all across Europe
Sub-option 1c	The aim of the policy measures included in this option is to **pull all flexible resources into the market**. The main policy measures studied in this report are: - Residential and storage demand-side response is allowed to participate in the reserve procurement process

	- Renewables can provide reserves
Option 2	The aim of this final option is to **fully integrate EU markets**. A supranational entity would be responsible for the dimensioning and procurement of reserves at an EU level.

As stated above, the goal of this report is to present the benefits of each of the options in terms of a number of indicators such as system costs, electricity cost, CO_2 emissions, etc. All impacts are measured against a baseline, which primarily consists of the current market arrangements.

Approach

The benefits associated with the options identified above have been estimated by running simulations of the European power system with the METIS model, which is developed for the European Commission by Artelys, with the support of IAEW (RWTH Aachen University), ConGas and Frontier Economics.

The impacts of the MDI options have been assessed by successively dimensioning reserves (regional cooperation tends to decrease reserve needs), jointly simulating the day-ahead electricity dispatch and the reserve procurement, simulating the adjustments of market participants' positions during the intraday timeframe, and finally simulating the use of the procured reserves to face imbalances in real-time. The power system and power market modules of METIS, which replicate the decision-making process of market participants, have been exploited in the context of this study.

METIS uses an hourly time resolution over one year (8760 consecutive time-steps per year), except when simulating balancing, in which case a 5-minute time resolution is adopted, and a country-level spatial granularity.

In all simulations, we adopt the installed capacities, transmission capacities (NTCs), fuel costs, CO_2 price and annual demand from the 2030 METIS EuCo27 scenario, which is itself calibrated on the 2030 PRIMES EuCo27 scenario. In some of the options, the transmission capacities available for certain market timeframes are increased or decreased compared to the PRIMES EuCo27 scenario to reflect the impact of policy measures.

Findings

Sub-option 1a generates most of its savings thanks to the removal of priority dispatch and of must-run arrangements. While this measure does only marginally impact PV or wind power, its effect on the dispatch of biomass is sizable. The lower level of must-take generation also results in 35% less curtailment. Finally, since RES become balancing responsible, the RES forecasts are assumed to become more precise. As a result around 30% less FRR reserves are needed. Sub-option 1a is found to generate savings of around 5.9 B€ compared to the baseline.

Sub-option 1b introduces the possibility for TSOs to procure part of their reserves abroad. The associated savings are of the order of 1.2 B€. If reserves are located abroad, TSOs have to reserve a share of the interconnection capacity accordingly. The average reserved capacity over the year and over interconnectors is found to be around 5.8% of the interconnection capacity. Furthermore, the removal of suboptimal reserve procurement practices is found to generate savings of the order of 1.5 B€. The measures introduced in Sub-option 1b are found to generate savings of 2.7 B€.

Sub-option 1c pulls further DSR resources into the market and allows variable RES to provide reserves. DSR is found to advantageously replace gas and hydro for upwards reserves, while the participation of RES in the provision of downwards reserves can avoid situations in which coal or gas plants are kept online only to provide downwards reserves. Sub-option 1c is found to result in an energy system that is around 0.9 B€ cheaper to operate than the one of Sub-option 1b.

Finally, reserves are dimensioned and procured at an EU level in Option 2. Reserve needs are significantly lower than in the baseline (-63%), but there in further competition for interconnection capacity: the system has to find a trade-off between procuring low levels of reserves (which requires to reserve interconnection capacity to exchange balancing energy) and a local provision of reserves, in which case the interconnection capacity can be used to exchange power rather than be reserved for mutual assistance between Member States.

Summary

Sub-option 1a	Sub-option 1b	Sub-option 1c	Option 2
Balancing responsibility 30% less mFRR to procure **Priority dispatch** Important impact on biomass dispatch (-85%) **Curtailment** Reduction of 35%	**Regional cooperation** 20 to 55% less FRR to procure depending on region (1.2 B€) **Regional cooperation** Reservation of 5.8% of cross-border transmission capacity **Optimal reserve procurement and asymmetric bids** 1.5 B€ savings	**Access to market** DSR and wind participate to reserves	**EU-wide cooperation** Further reduction of FRR to be procured, but further competition for interconnection capacity
Savings: 5.9 B€ (Compared to Baseline)	**Savings: 2.7 B€** (Compared to 1a)	**Savings: 0.9 B€** (Compared to 1b)	**Savings: 1.1 B€** (Compared to 1c)

Limitations

The estimates reported in this study are based on modelling which relies on a number of assumptions in terms of inputs. Changes to the input dataset may materially change the outputs.

The dimensioning of reserves is based on a probabilistic approach. The results may differ if one were to consider the deterministic approach currently used by many Member States. METIS also assumes that the 2030 markets will be perfectly liquid, which is not what is currently observed in many Member States. The analysis is based on an NTC description of the network, which does not capture costs related to congestion within Member States.

Moreover, one should note that the effects of removing priority dispatch for CHP are not captured in the assessment. In particular, CHP and small scale RES-e are not modelled as separated assets and gas units are assumed to be flexible in all the MDI options. It can be expected that taking into account current priority dispatch practices for CHPs, which produce around 11% of the EU28 electricity in the PRIMES 2030 EuCo27 scenario, would increase the baseline production costs. Besides, taking into account the heat supply constraints that could apply to gas and biomass CHPs would reduce the flexibility of all options and increase their costs.

Finally, the impact of producer revenues on investments is not analysed in this report. Moreover, the model used for this study does not include any RES investment premiums or capacity remunerations, as it focuses on the short-term management of the power markets.

3. INTRODUCTION AND BACKGROUND

The present document has been prepared by Artelys in response to the Terms of Reference included under ENER/C2/2014-639[1]. Readers should note that the report presents the views of the Consultant, which do not necessarily coincide with those of the Commission.

3.1. INTRODUCTION AND STRUCTURE OF THE REPORT

This report aims at supporting the Commission by evaluating the impacts associated with a range of options designed to improve the functioning of the European electricity markets. The goal of the Market Design Initiative[2] is to reduce the inflexibility of the current market arrangements, to better interconnect short-term markets and to pull further flexible resources into the market. The measures discussed in this report, which have been grouped in coherent packages by the European Commission prior to this analysis, have been simulated using the METIS model, which is currently being developed by Artelys, with the support of IAEW (RWTH Aachen University), ConGas and Frontier Economics.

This report aims at allowing the Commission to compare the impacts of several MDI options by quantifying the economic, social and environmental consequences of implementing these options. In the remainder of this Section, we provide further details regarding the scope and objectives of the report, and provide a brief background on the relevance of this work to the currently ongoing regulatory and legislative efforts.

Section 4 provides a detailed description of the MDI options considered in this analysis. Measures aimed at improving the functioning of the electricity markets are progressively introduced: Option 1 aims at increasing the flexibility of the electricity system and is further sub-divided in three sub-options, while Option 2 corresponds to a fully integrated EU market. The first set of measures (Sub-option 1a) targets the current market inefficiencies and ensure a level playing field is introduced for all technologies. The second set of measures (Sub-option 1b) further reinforces the level of regional cooperation (reserve dimensioning and procurement), removes the currently observed suboptimal reserve procurement practices, and makes better use of interconnections. The final set of measures introduced under Option 1 (Sub-option 1c) is designed to pull further flexible distributed resources into the market (e.g. RES, DSR, storage). Finally, the most ambitious option (Option 2) would effectively result in the introduction of regional transmission operators, which would dimension and procure reserves at an EU level, and which would be able to even better exploit the management of the European transmission system.

Section 5 provides a quantitative assessment of the impacts of the measures introduced in Section 4. A number of metrics are used to allow for an accurate comparison of the impacts of the different options. Whenever possible, the report identifies the impacts of individual policy measures, but it has to be noted that since policy measures are introduced in packages, it may not be possible to precisely identify the impacts of each policy measure.

Section 6 provides a summary of the analysis presented, drawing out the key conclusions for the Market Design Initiative Impact Assessment.

3.2. SCOPE AND OBJECTIVES OF THE ANALYSIS

This report provides quantitative estimates of the impacts of four stylised policy options of market design development of increasing levels of ambition, which have been designed by the European Commission by grouping policy measures into coherent packages. The measures under scrutiny include the phase-out technology-specific measures, and the

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[1] http://ec.europa.eu/dgs/energy/tenders/doc/2014/2014s_152_272370_specifications.pdf

[2] See COM(2015) 80 final for more details.

strengthening of the role of cooperation between TSOs and NRAs through bodies introduced in the 3rd Internal Energy Market Package.

The impacts have been evaluated using a model of the European energy sector, which is described in *METIS Technical Note T2 – Power Market Models*. The METIS module that is used in this report focuses on the electricity sector: it represents power system and markets. METIS replicates the functioning of the electricity markets by simulating the dimensioning and procurement of reserves, the day-ahead dispatch of electricity, the adjustments of market participants' positions in the intraday markets, and the utilisation of reserves to balance the system in real-time.

The METIS model has been calibrated to reflect the main characteristics of the 2030 PRIMES EuCo27 scenario. The procedure is described in *METIS Technical Note T1 – Methodology for the integration of PRIMES scenarios into METIS*. In particular, all the assumptions related to the installed capacities, fuel prices, CO2 price, NTCs, annual demand originate from the 2030 PRIMES EuCo27 scenario.

The implementation in METIS of the various policy measures investigated in this study are described in details in *METIS Technical Note T3 – METIS market module configuration for Study S12*. This report contains an overview of each of the options so as to allow the reader to understand what mechanisms drive the economic, social and environmental benefits of each of the policy options assessed in this study.

4. DESCRIPTION OF THE POLICY OPTIONS

This section is devoted to the presentation of the four packages of measures designed by the European Commission whose impacts have been evaluated in this report. The baseline corresponds to the current market arrangements. Policy measures are then progressively introduced to form coherent packages: Sub-option 1a, Sub-option 1b, Sub-option 1c, and Option 2.

4.1. BASELINE – CURRENT MARKET ARRANGEMENTS

The baseline reflects the current market arrangements and assumes no new legislation is adopted. Efforts are however made to implement existing legislation via the adoption of the network codes (in particular the adoption of the Guideline on Electricity Balancing, which is expected to generalise imbalance netting practices and to allow EU-wide cross-border exchanges of balancing energy via a common merit order list). The day-ahead markets are assumed to be coupled by 2030, while status of intraday market coupling is assumed to be the same as the current situation (EPEX, Nordpool and MIBEL are assumed to use implicit auctions, while all other regions use explicit auctions).

In this option, the EU power markets retain a large part of their current national characteristics:

- Must-take arrangements (mainly affecting biomass and waste-fired units) and priority dispatch rules (for wind, PV and run-of-the-river units) during the day-ahead timeframe are maintained,
- The curtailment of RES units is assumed to be penalised,
- Coal and lignite units are assumed not to update their commitment during the intraday timeframe (must-run arrangements),
- Balancing responsibility for RES producers is not generalised across the EU,
- The dimensioning and procurement of reserves are performed at the national level,
- Countries which currently use suboptimal reserve procurement practices such as joint upwards and downwards procurement and fixed allocation of synchronised reserves to large thermal units do not update their practices[3].

All the effects of the MDI policy options will be measured against the baseline.

4.2. SUB-OPTION 1A – REDUCING CURRENT INFLEXIBILITY

The package of measures introduced in Sub-option 1a aims at reducing the current inflexibility of the power system and markets by introducing new legislation targeting the removal of existing market distortions and creating a level playing field amongst technologies. The main assumptions reflecting the policy measures are:

- Must-take and priority dispatch rules are abandoned. Biomass units are allowed to participate in the reserve procurement process.
- RES can be curtailed without penalties, if cost-effective from a systems point of view (technically constrained merit order)
- All market participants are assumed to be balance responsible, including RES producers
- Must-run arrangements for coal and lignite units are phased-out.

[3] The following countries currently adopt suboptimal FCR procurement practices: BE, EE, ES, FR, HR, IT, LT, LV, PT, SI, SK, UK. The following countries currently adopt suboptimal aFRR procurement practices: EE, FR, LT, LV, UK. The following countries currently jointly procure upwards and downwards aFRR reserves (source: COWI): BE, DK, EE, ES, FR, HR, IT, LT, LV, PL, PT, RO, SI, SK, UK. Source: “Electricity Market Functioning: Current Distortions, and How to Model Their Removal”, COWI (2016).

The focus of Sub-option 1a is to reduce the inflexibility of the current market arrangements, further flexibility will be introduced in the following options. Therefore, TSOs are still assumed to dimension and procure balancing reserves at national level, but EU-wide imbalance netting and cross-border exchange of balancing energy are allowed, as in the baseline.

4.3. SUB-OPTION 1B – BETTER MARKET INTERCONNECTION

Sub-option 1b introduces an additional package of measures to not only remove further market distortions, but most importantly to increase the level of competition in the internal market be enhancing regional cooperation and make better use of interconnection capacities. MS are therefore able to exchange resources across all timeframes and to take advantage of the different dynamics of demand peaks and weather conditions across Europe. The main assumptions reflecting the policy measures are:

- All suboptimal reserve procurement practices are abandoned,
- Reserve needs depend on the hour of the day and on wind generation forecasts,
- Upwards and downwards reserves are assumed to be procured independently,
- Reserves are dimensioned and procured at the regional level
- The strengthened collaboration among TSOs is assumed to result in a higher interconnection capacity available to market participants (+ 5% with respect to the baseline).
- The implicit coupling of intraday markets is generalised all across Europe

The focus of Sub-option 1b is to increase the level of flexibility by better interconnecting short-term markets. Further flexibility resources are introduced in the next option.

4.4. SUB-OPTION 1C – PULL ALL FLEXIBLE RESOURCES INTO THE MARKET

Sub-option 1c builds up on Sub-option 1b and introduces new legislation to improve the market framework to pull all the available resources into the market. Measures are introduced to incentivise the demand-side to react to wholesale market prices and become active participants in the market (directly or through aggregators). The main assumptions reflecting the policy measures are:

- Variable RES are eligible to participate in the reserve procurement process,
- Further DSR resources (residential, storage) can provide reserves.

4.5. OPTION 2 – FULLY INTEGRATED EU MARKET

Option 2 would result in a significant evolution of the current design in which European electricity systems are operated. The main assumptions reflecting the policy measures are:

- A supranational entity would be responsible for the dimensioning and procurement of balancing reserves at an EU level. TSOs would still be responsible for real-time activation: they would have access to an EU platform for the procurement of balancing reserves which would foresee daily auctions separating upwards and downwards bids.
- The further strengthening of cooperation between TSOs, the cross-border transmission capacity is assumed to be 5% more important than in Sub-options 1b and 1c.

4.6. IMPLEMENTATION IN METIS

The impacts of the policy options described in the previous sections have been assessed by simulating the operations of the European power system with METIS. The METIS model results from an effort initiated by DG ENER to further support its evidence-based policy making process, especially in the areas of electricity and gas systems and markets. METIS has been designed so as to be able to represent the measures composing the policy options under scrutiny in this study.

METIS is a bottom-up model of the European power and gas systems and markets. It uses an hourly time resolution (8760 consecutive time-steps per year) and a country-level spatial granularity. Generation technologies characteristics include availability, efficiency, ramping rates, minimum time off, minimum stable generation, etc. The exchange of power and reserves are constrained by the net transfer capacities (NTC) of interconnectors. This study only exploits the power system and power market modules.

METIS jointly optimises power generation and reserve procurement: the commitment of units is not only constrained by the supply-demand equilibrium constraint, but also by the reserves they collectively have to provide. As a consequence it is not possible to totally disentangle the day-ahead costs of power generation from the costs of reserve procurement. METIS then simulates the refinement of market participants' positions during the intraday market by taking into account the better RES and demand forecasts that become available during this timeframe. Finally, METIS optimises the use of the reserves (procured during the day-ahead timeframe) to face imbalances in real-time. More details are available in *METIS Technical Note T2 – Power Market Models*.

METIS uses the METIS 2030 EuCo27 scenario throughout this study. This scenario has been calibrated to replicate the main characteristics of the PRIMES 2030 EUCO27 scenario (*METIS Technical Note T1 – Methodology for the integration of PRIMES scenarios into METIS*): installed generation capacities4, transmissions capacities, fuel prices, CO2 cost, annual demand, etc.

The impact of producer revenues on investments is not analysed in this report and the model used for this study does not include any RES investment premiums or capacity remunerations, as it focuses on the short-term management of the power market.

A summary of way each of the MDI policy options is represented in METIS is provided in **Table 2**.

Table 2 - Representation of the MDI options in METIS

Concept	Baseline	Sub-option 1a	Sub-option 1b	Sub-option 1c	Option 2
Reserve dimensioning	Fixed over the year	Fixed over the year	Variable	Variable	Variable
Reserve dimensioning and procurement	National	National	Regional	Regional	EU
Reserve procurement[5]	Suboptimal	Suboptimal	Optimal	Optimal	Optimal
Interconnection	NTC – 5%	NTC – 5%	NTC	NTC	NTC + 5%

[4] The capacities of peaking units have been optimised in order to be compatible with a given level of reliability.

[5] The following countries currently adopt suboptimal FCR procurement practices: BE, EE, ES, FR, HR, IT, LT, LV, PT, SI, SK, UK. The following countries currently adopt suboptimal aFRR procurement practices: EE, FR, LT, LV, UK. The following countries currently jointly procure upwards and downwards aFRR reserves (source: COWI): BE, DK, EE, ES, FR, HR, IT, LT, LV, PL, PT, RO, SI, SK, UK. Source: "Electricity Market Functioning: Current Distortions, and How to Model Their Removal", COWI (2016).

Interconnection reservation for balancing	No	No	Yes	Yes	Yes
Upwards and downwards bids[5]	Joint	Joint	Separate	Separate	Separate
RES participation to reserve procurement	No	No	No	Yes	Yes
DSR participation in reserve procurement[5]	Industrial only	Industrial only	Industrial only	All resources	All resources
RES priority dispatch	Yes	No	No	No	No
Generalisation of RES balancing responsibility	No	Yes	Yes	Yes	Yes
Coal and lignite re-commitment in intraday	No	Yes	Yes	Yes	Yes
Intraday market coupling	Partial	Partial	EU-wide	EU-wide	EU-wide

The following paragraphs succinctly describe some of the concepts appearing in the previous table. More details can be found in *METIS Technical Note T3 – METIS market module configuration for Study S12*.

- **Reserve dimensioning**
  In the baseline and Sub-option 1a, reserve needs are assumed to be constant over the whole year. In all other options, aFRR reserve needs depend on the state of the system (mainly impacted by demand and wind production), which results in lower reserve requirements. FCR and mFRR needs are assumed to remain constant over the whole year.

  In the baseline and Sub-option 1a, the reserve needs are computed at the national level allowing each of the countries to cover their own imbalances independently. In Sub-option 1b and 1c, the reserve needs are computed at regional level, which results in lower needs thanks to the risk pooling effect: the probability that imbalances cancel each other increases as one increases the area on which they are observed. Finally in Option 2, the needs are computed at an EU-level, which results in even lower needs.

- **Reserve procurement**
  In the baseline and Sub-option 1a, one assumes that the countries which currently have suboptimal procurement practices (reserves provided by baseload thermal units only, the amount of reserve provided by each of the involved thermal units is fixed over the whole year) carry on using suboptimal practices[6]. In all further options, suboptimal procurement practices are assumed to be abandoned, meaning that reserves are procured on an hourly basis during the day-ahead market, and that all plants that meet the technical requirements can participate in the procurement.

- **Interconnection and reservation**
  The interconnection capacity available to exchange power and reserves is assumed to reflect the gains emerging from a tighter collaboration between TSOs in Sub-option 1b, Sub-option 1c and Option 2. Moreover, since these options assume a

[6] The following countries currently adopt suboptimal FCR procurement practices: BE, EE, ES, FR, HR, IT, LT, LV, PT, SI, SK, UK. The following countries currently adopt suboptimal aFRR procurement practices: EE, FR, LT, LV, UK. Source: "Electricity Market Functioning: Current Distortions, and How to Model Their Removal", COWI (2016).

regional or EU-wide dimensioning of reserve needs, it is necessary that interconnection are reserved accordingly so as to ensure balancing energy can be exchanged by MS.

- **Upwards and downwards bids**
  In the baseline one assume that the upwards and downwards reserves are jointly procured, except in countries which already have separate reserve procurement practices[7]. In a country using suboptimal practices, units providing reserves are constrained to simultaneously provide upwards and downwards regulation. Sub-option 1b, Sub-option 1c and Option 2 assume that these practices are phased out in all countries and that upwards and downwards balancing reserves are procured independently.

- **RES priority dispatch**
  In the baseline, one assumes RES energy (PV, wind, hydro, biomass) to be dispatched ahead of all other generators during the day-ahead timeframe. In case RES have to be curtailed as a last resort measure to balance the system in real-time, a 10€/MWh penalty is applied. In all other policy options, priority dispatch is abandoned. As a result, RES is only dispatched if cost-effective from a system point of view (technically constrained merit order).

- **RES balancing responsibility**
  Subjecting RES to balancing responsibility would result in penalising deviations from their schedule. It is expected that RES producers would seek to better their forecasts so as to predict their power output more precisely and to avoid penalties. METIS mimics the consequences of this behaviour by improving the quality of the forecasts used when dimensioning mFRR needs: h-2 forecasts are replaced by h-1 forecasts when RES is subject to balancing responsibility.

- **Coal and lignite re-commitment in intraday**
  In the baseline, it is assumed that the coal and lignite units whose commitment is accepted by the day-ahead market benefit from must-run arrangements during the intraday market. All other policy options assume that coal and lignite units should adapt both their commitment and power output during intraday, provided they respect their technical constraints, in order to adapt to demand and RES variations.

- **Intraday market coupling**
  In the baseline and Sub-option 1a, one assumes that interconnection can adjust their flows in intraday up to h-4 (explicit auctions) except in the EPEX, Nordpool and MIBEL countries, which can adapt their internal interconnection schedules until h-1. In all other options, the intraday markets are assumed to be coupled, which is mimicked by allowing all interconnections to update their schedules until h-1.

[7] The following countries have already adopted separate upwards and downwards reserve procurement practices: AT, BG, CH, CZ, DE, FI, GR, HU, IE, NL, NO, SE. Source: "Electricity Market Functioning: Current Distortions, and How to Model Their Removal", COWI (2016).

5. IMPACTS OF POLICY OPTIONS

This section presents the results obtained by simulating the behaviour of the European power system for each of the policy options introduced in Section 4. When possible, we identify and comment the impacts of a number of policy measures. Each option is evaluated and compared with the baseline using a number of key indicators:

- **Total costs** of the energy system (in B€) divided in:
  - **Day-ahead costs:** cost of operating the European power system to ensure the supply-demand equilibrium for electricity is met and required level of balancing reserves is procured in day-ahead. These costs include fuel costs, start-up and running costs of power plants, costs related to CO_2 emissions, costs of demand and RES curtailment.
  - **Intraday costs:** cost of operating the European power system to refine the generation schedule between day-ahead and intraday after new information (e.g. demand and RES generation) has been acquired, thereby bringing the market back in balance.
  - **Balancing costs** split between **upwards balancing costs** corresponding to the increase of generation costs in the power system is short, and **downwards balancing costs** in case the power system is long. The downwards costs are negative since, in order to face the imbalance, the system has to reduce its output and thereby decrease its generation costs (fuel costs).
- **Gross CO_2 emissions** (in $MtCO_2$), emissions caused by the combustion of fuel for electricity production and reserve procurement.
- **Load payment** (in B€), sum over the year of the product between the hourly day-ahead electricity price and electricity demand. It corresponds to the financial transaction between the European power suppliers and generators for the provision of electricity on the wholesale day-ahead market.
- **Weighted average price of electricity** in (€/MWh), demand-weighted average day-ahead electricity wholesale price.

5.1. SUB-OPTION 1A - REDUCING CURRENT INFLEXIBILITY

The measures introduced in this policy package aim at reducing the current inflexibility of the power system by removing technology-specific rules. Since all the measures discussed in Section 4.2 are introduced simultaneously, one can only observe the collective impact of the policy package. However, some of the impacts can be understood as predominantly resulting from the introduction of a given policy measure. These impacts are discussed below.

<u>Generalisation of RES balancing responsibility</u>

The first measure having identifiable impacts is the generalisation of balancing responsibility in all Member States. It is assumed that RES producers will be incentivised to increase the accuracy of their RES generation forecasts (wind and PV generation in particular) in order to avoid financial penalties. As a result of the reduction of forecast errors, the power system needs a lower level of balancing reserves. Since aFRR needs mainly depend on 5-min fluctuations, mFRR is the main benefactor from the generalisation of balancing responsibility. The relative decrease of reserve needs compared to the baseline is found to be around 17%, and is mainly driven by the mFRR reduction (around 30%) as can be read from **Table 3**.

Table 3 - Reserve needs for Sub-option 1a and comparison with baseline

Reserve needs (GW)		Baseline	Sub-option 1a
Active power	**Upwards**	16.7	16.7
	Downwards	16.2	16.1
mFRR	**Upwards**	23.5	17.4
	Downwards	23.2	15.6
Total		**79.6**	**65.8**
Reduction of reserve needs		-	17%

The generalisation of balancing responsibility, through the assumed enhancement of RES generation forecasts, results in less balancing capacity to be procured during the day-ahead timeframe, and thereby contributes to lower the day-ahead costs.

Removal of priority dispatch

The second measure that has easily identifiable impacts is the removal of priority dispatch practices. In the baseline, priority dispatch ensures that the electricity produced by technologies such as wind turbines, PV panels, run-of-the-river units, biomass plants is injected into the power network, irrespective of the variable costs of these technologies. As a result, these technologies are maximising their power outputs and adopt a "must-take" behaviour in the baseline. Furthermore, the curtailment of PV and wind power, which may be necessary to maintain the balance of the power system, is assumed to be penalised in the baseline, leading to negative prices at times PV or wind have to be curtailed.

The removal of priority dispatch rules aims at restoring a merit-order-based dispatch of electricity. The measure mainly affects those units that are characterised by high variables costs, since their bids are less likely to be accepted. In contrast, the dispatch of PV and wind power, which both have very low variable costs, is only marginally impacted. In particular, our results show that a large share of the biomass production is replaced by other cheaper technologies in Sub-option 1a. This effect is due to the high variable costs associated with biomass production in the EuCo27 scenario[8]. This scenario indeed assumes that the biomass variable cost is larger than the variable costs of both coal and gas production. The power that used to be generated by expensive wood-based generation units is compensated for by cheaper generation technologies, mostly nuclear power plants, and coal- and gas-fired units. The biggest impacts on generation are observed in Denmark, UK and Finland, where biomass holds a large share of generation capacity.

Figure *2* presents the impact of Sub-option 1a on the day-ahead dispatch of electricity. One should note that the effect is not solely due to the removal of priority dispatch: since the reserve needs are lower in Sub-option 1a, some units that were participating in the reserve procurement in the baseline can dedicate more capacity to the provision of electricity in Sub-option 1a.

[8] Biomass units are modelled as wood-fired generators, except for waste units which are treated specifically. Constraints which would require CHP biomass to be kept online to produce heat are not considered. This assumption may lead to an over-estimation of the flexibility of biomass units.

Figure 2 – Impact of Sub-option 1a on day-ahead dispatch

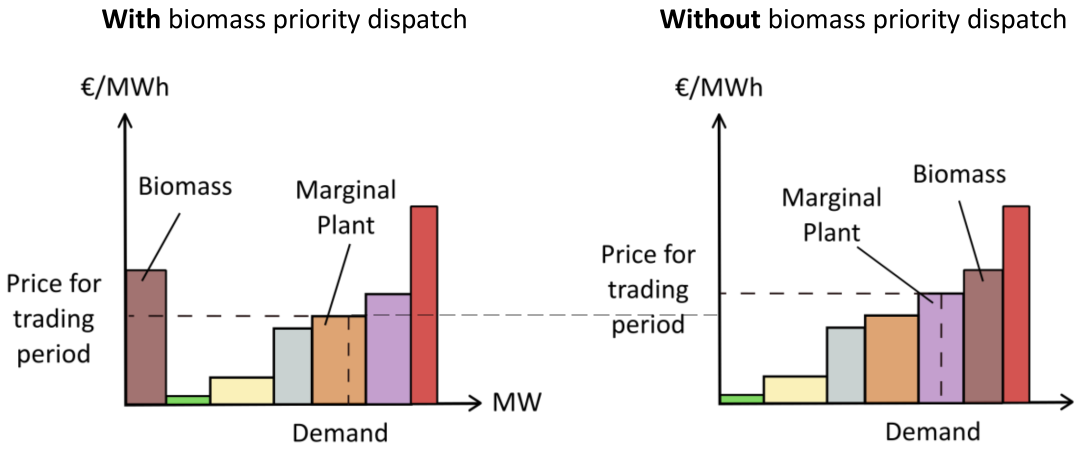
	Biomass	Hydro	Nuclear	Coal	Gas
Impact (TWh)	-160	-10	+20	+35	+90
Baseline production (TWh)	185	630	755	235	455

The removal of priority dispatch therefore negatively impacts CO_2 emissions, since coal and gas increase their production. CO_2 emissions increase by 60 Mt, while day-ahead fuel costs decrease by around 8 B€. Since most of this effect can be attributed to the removal of priority dispatch, one can estimate that reducing emissions via priority dispatch costs around 130 € per tonne of CO_2. A sensitivity analysis to CO_2 price presented in Appendix A shows that a CO_2 price of 60 €/tonne would trigger enough coal to gas and biomass switching to maintain the same emissions in Sub-option 1a as in the baseline.

Moreover, the removal of priority dispatch has an influence on day-ahead prices. ***Figure 3*** presents the distortion of the merit order[9] when expensive technologies benefit from priority dispatch. In this illustration, biomass priority dispatch tends to shift the merit order to the right, resulting in a lower market clearing price and higher system costs. Removing priority dispatch thus reduces the cost of operating the power system at times where biomass would be out-of-the-money, and increases the electricity price during these hours. The day-ahead weighted average wholesale price of electricity is found to increase by around 5% in Sub-option 1a compared to the baseline. This higher electricity price tends to increase the revenues of base-load RES and thermal units.

[9] Each generation fleet is represented synthetically as a block, as large as its power capacity and as high as its generation cost. In the absence of market distortions, the market dispatches the lowest (cheapest) blocks first, until the demand is met. The generation cost of the most expensive dispatched power plant sets the clearing price.

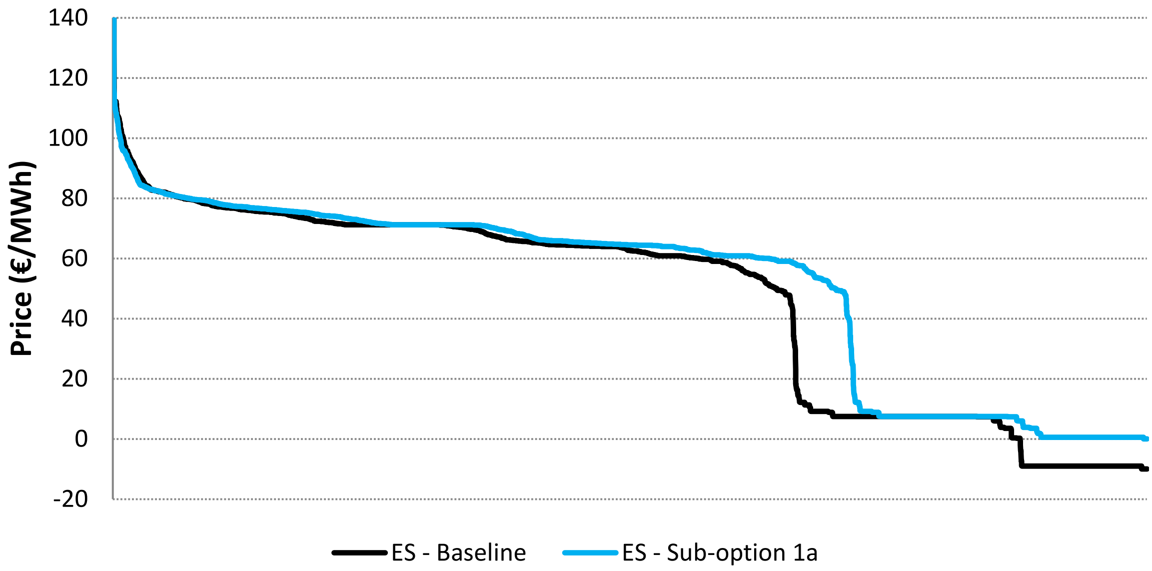
Figure 3 - Merit order distortion induced by the introduction of priority dispatch



Another effect of the removal of priority dispatch is that it allows for more PV, wind, run-of-the-river and waste-fired generation to be injected in the European power system, thanks to a decrease of curtailment. Indeed, if biomass is always operated at is maximum available capacity, the total planned day-ahead generation can exceed the demand, which triggers negative prices and curtailment of RES in the baseline. The removal of priority dispatch in Sub-option 1a lowers the "must-take" capacity and therefore the occurrence of situations in which generation exceeds the demand.

Figure 4 presents the Spanish price duration curve: one can observe that negative prices are eliminated (since priority dispatch is removed for RES, there is no penalty attached to its curtailment) and that the number of hours of curtailment decreases. In terms of energy, it is found that curtailment decreases by around 35% (from 13 TWh in the baseline to 8 TWh in Sub-option 1a).

Figure 4 – Spanish price duration curve (baseline and Sub-option 1a)



Re-optimisation of coal and lignite commitment in intraday

The next measure we illustrate impacts the flexibility available during the intraday timeframe. Sub-option 1a removes the must-run arrangements for coal and lignite units during the intraday market. This incentivises coal and lignite plants to turn units on or off (provided they respect technical constraints such as start-up time) according to improved intraday forecasts of RES generation and power demand. This additional flexibility brought by coal and lignite power plants helps the power system to face unplanned surges of demand or lower than expected RES generation during the intraday timeframe. As a result, resorting to expensive gas- or oil-fired generation and the activation of replacement reserves[10] can partly be avoided.

Figure 5 presents the localisation of the avoided activation of replacement reserves, thanks to the additional flexibility brought by the ability for coal and lignite plants to re-optimise their commitment during the intraday timeframe. The impacts are most visible in coal-intensive regions such as Central and Eastern Europe, where around 450 GWh of replacement reserve activation is avoided.

Figure 5 - Avoided replacement reserve activations in Sub-option 1a

Summary

All the policy measures introduced in Sub-option 1a aim at reducing or eliminating some of the current inefficiencies of the European power system, and to ensure all technologies compete on a level playing field.

As previously mentioned, only the most important impacts have been illustrated in this section. Other measures such as biomass to provide reserves only marginally influence the behaviour of the system and have therefore not been discussed.

CO_2 emissions are found to increase in Sub-option 1a due to the partial replacement of biomass by cheaper but more CO_2-intensive technologies such as coal and gas fleets[11]. The weighted day-ahead average wholesale electricity price is also found to increase as a consequence of the mechanism illustrated in ***Figure 3***.

[10] Although replacement reserves are not explicitly represented in METIS, it is assumed that some of the loss of load situations would be avoided by using replacement reserves (with cost assumptions of 60 k€/MW/year and 180 €/MWh). More details can be found in *METIS Technical Note T2 - METIS Power Market Models*.

[11] A sensitivity analysis to the price of CO_2 has been performed to estimate what level the CO_2 would have to reach in order to recover the baseline CO_2 emissions when introducing the Sub-option 1a policy measures. This analysis is presented in Appendix A

In summary, the policy measures introduced in Sub-option 1a result in a reduction of the annual costs of around 7% or 5.9 B€. **Table 4** shows how each of the considered timeframes (day-ahead, intraday, and balancing) contribute to these savings.

Table 4 - Key figures for MDI Sub-option 1a

Indicator	Baseline	Sub-option 1a
Cost day-ahead (B€)	82.5	76.9
Cost intraday (B€)	1.4	0.9
Cost balancing (B€)	- 0.5	- 0.3
of which upwards	0.7	0.5
of which downwards	- 1.2	- 0.8
Total costs (B€)	**83.4**	**77.5**
Savings (B€)	-	5.9
Load payment (B€)	278	293
Weighted average price (€/MWh)	79	83
Energy (TWh)	3620	3610
CO_2 emissions (Mt)	555	615

5.2. SUB-OPTION 1B - BETTER MARKET INTERCONNECTION

The measures introduced in this policy package aim at better interconnecting short-term markets. Since all the measures discussed in Section 4.3 are introduced simultaneously, one can only observe the collective impact of the policy package. However, some of the impacts can be understood as predominantly resulting from the introduction of a given policy measure. These impacts are discussed below.

<u>Regional dimensioning of frequency restoration reserves</u>

Sub-option 1b introduces regional cooperation in the field of FRR dimensioning[12]. Thanks to the fact that imbalances happen at different times in different countries, the reserve needs computed at a regional level are lower than the sum of the national needs. Furthermore, one takes into account the demand and RES generation profiles when dimensioning reserves in Sub-option 1b: the reserve needs can therefore depend on the hour of the day and on wind generation forecasts[13]. Finally, upwards and downwards reserve needs are assumed to be independent for all Member States in Sub-option 1b. **Table *5*** shows how active power and mFRR needs are impacted by these measures. The fact that active power needs decrease less quickly than the mFRR ones is mainly due to the fact that FCR needs are assumed not to be impacted by regional dimensioning.

[12] FCR already benefits from regional cooperation as it is dimensioned at the synchronised area level. It is therefore assumed not to be impacted by this measure.

[13] Wind forecast errors are generally found to be much higher during windy periods.

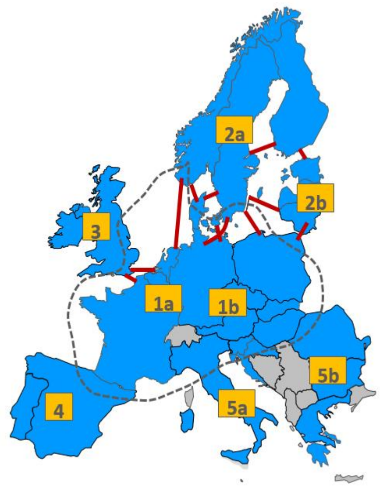
Table 5 - Reserve needs for Sub-option 1b and comparison with baseline

Reserve needs (GW)		Baseline	Sub-option 1a	Sub-option 1b
Active power	**Upwards**	16.7	16.7	11.5
	Downwards	16.2	16.1	11.0
mFRR	**Upwards**	23.5	17.4	10.2
	Downwards	23.2	15.6	9.6
Total		**79.6**	**65.8**	**42.3**
Reduction of reserve needs		-	17%	47%

Since the phenomenon that predominantly drives the decrease of reserve needs is the statistical cancellation of imbalances (regional cooperation)[14], one can expect that larger regions benefit predominantly from this measure. This is indeed the case, as is illustrated by **Figure *6***: large regions such as regions 1, 2 and 5 benefit from FRR needs reduction of up to 55%, while smaller regions see their FRR reserve needs decrease by 20% at best.

Figure 6 - Reduction of FRR needs by region in Sub-option 1b

	FRR needs reduction
Region 1	55%
Region 2	50%
Region 3	20%
Region 4	20%
Region 5	45%



<u>Regional procurement of reserves</u>

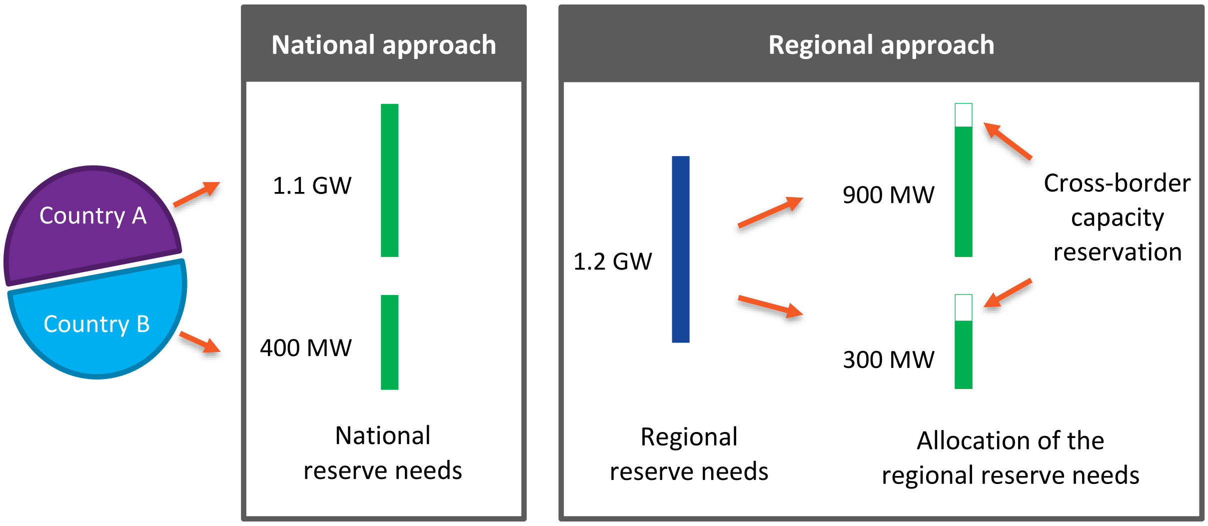
As discussed above, Sub-option 1b assumes that active power and mFRR needs are dimensioned at the regional level. Mutual assistance between Member States therefore has to compensate for the decrease of reserve needs between Sub-options 1a and 1b. This means that, in order for individual countries to continue to be able to face the same imbalance risks, interconnection capacity has to be reserved in order to import/export

[14] Without regional cooperation, the reserve needs of Sub-option 1b would still be lower than the reserve needs of Sub-option 1a thanks to the removal of suboptimal procurement practices (symmetric reserves) and the hourly dimensioning of reserves. In such a case, the reserve needs would have been: 16.4 GW for active power upwards reserves, 15.1 GW for active power downwards reserves, 17.4 GW for upwards mFRR and 15.6 GW for downwards mFRR.

balancing energy. TSOs can also decide to procure more reserves locally and reserve less interconnection capacity, in order to make it available to electricity market participants.

Figure 7 illustrates how the regional balancing needs are allocated to countries, and the trade-off between a local provision of balancing capacity and interconnectors' reservation.

Figure 7 - Trade-off between local provision of reserves and interconnectors' reservation



In this fictitious example, we illustrate the impact of a regional dimensioning of upwards active power reserves in Country A and Country B. The nationally-determined reserve needs allow both countries to independently face their respective risks. In this situation, Country A has to procure 1.1 GW of upwards active power reserves, and Country B 400 MW. When the dimensioning is performed at the regional level, the statistical cancellation of imbalances results in a regional requirement of 1.2 GW, which is lower than the sum of the nationally-determined reserve needs (1.2 GW vs 1.5 GW). Each of the countries is assumed to procure a share of the regional reserve needs, according to their annual electricity demands. In our fictitious example, Country A has to procure at least 900 MW and Country B at least 300 MW.

In order to face their imbalance risks (due to forecasting errors, outages, etc.), both countries have to secure access to the amount of reserve computed using a national approach. This reserve might either be procured locally, or be provided by another country:

- Country A therefore has to choose how to secure the 200 MW between its national needs (1.1 GW) and the local share of the regional needs (900 MW). Country A can for example choose to procure 100 additional MW and to reserve 100 MW on interconnectors. Country A would then have 1.0 GW of local reserves, and 100 MW reserved on interconnectors. The total would allow Country A to face its imbalance risks (1.1 GW).

- Country B faces the same choice, only for 100 MW. It could for example choose to procure the entire local needs (400 MW) locally, so as to maximise the import capacity from Country A.

This example illustrates the trade-offs between a local procurement of reserves, and the reservation of cross-zonal transmission capacity.

Table *6* presents the average interconnection capacity reservation for each reserve type. The reserve needs in the first column are the one of Sub-option 1b without regional cooperation. The second column shows how much reserve capacity is procured by the model, while the third column is the difference between the first two. On average, 5.8%

of the EU interconnection capacity is found to be reserved for cross-border exchanges of balancing energy.

In particular, one may note that interconnections are mostly used for upwards reserve procurement. The optimal trade-off is indeed to procure downwards reserves locally (since they tend to be cheap and abundant), so as to be able to use interconnections for electricity trading.

Table 6 – Average interconnection reservation in Sub-option 1b

Reserves (GW)		Needs to face same risk level	Procured in Sub-option 1b	Provided by neighbours	Interconnection capacity reservation
Active power	**Upwards**	16.4	11.7	4.7	2.2%
	Downwards	15.1	14.5	0.6	0.3%
mFRR	**Upwards**	17.4	10.6	6.8	3.2%
	Downwards	15.6	15.5	0.1	0.1%
Total		**64.5**	**52.3**	**12.2**	**5.8%**

The interconnection reservation figures presented in the table above are an average over the year and over interconnectors. Small regions will tend to have to reserve a larger share of their interconnection capacity since there are fewer Member States that can assist a given country to face its local imbalances. **Table *7*** presents the average interconnection capacity reservation figures at the regional level. One should note that whereas the interconnection reservation figures in **Table *6*** are based on the EU interconnection capacity, the ones of **Table *7*** only take into account the internal interconnections of each of the regions.

Table 7 – Average interconnection reservation in Sub-option 1b

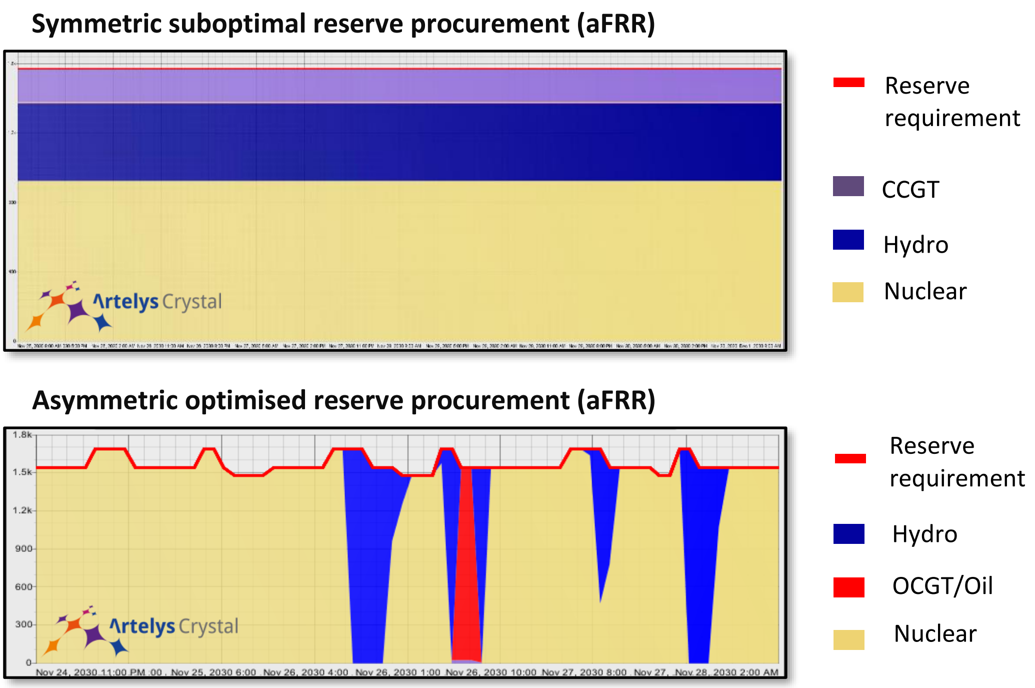
Reserves (GW)	Needs to face same risk level	Procured in Sub-option 1b	Provided by neighbours	Interconnection capacity reservation
Region 1	27.7	20.4	7.3	8.1%
Region 2	11.5	9.5	2.0	7.6%
Region 3	7.0	6.5	0.5	19.0%
Region 4	7.1	6.4	0.7	8.6%
Region 5	9.9	8.3	1.6	13.7%

<u>Removal of suboptimal reserve procurement practices</u>

The reserve procurement process in Sub-option 1b is not only improved by allowing regional cooperation between Member States, but also by removing current suboptimal practices. In a number of countries, the reserved needs remain constant over the whole year. Moreover, it is often the case that these countries allocate reserves to large thermal units[15]. In some cases, these units have to provide the same amount of upwards and downwards reserves. All these effects resulting in a suboptimal utilisation of resources.

As discussed above, the dimensioning of reserves in Sub-option 1b can depend on the hour of the day, reflecting the structure of the demand and the importance of variable RES in the generation mix. Furthermore, upwards and downwards reserves are procured independently, which leads to upwards reserve being mainly provided by marginal units, while marginal or sub-marginal units provide downwards reserve. In the example presented in **Figure *8***, one can observe that when removing suboptimal procurement practices, the power system is able to optimally pick the technology that is the best suited to provide reserves for each time-step, while satisfying all technical constraints (gradients, min off time, etc.).

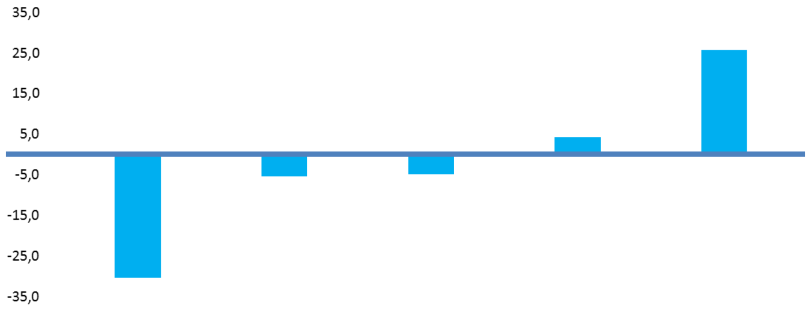
Figure 8 - Moving from suboptimal to optimal reserve procurement practices in Sub-option 1b



This measure, combined with the more efficient use of interconnections (NTC are assumed to be increased by 5% with respect to the baseline scenario), leads to a better use of cheap generation technologies such as nuclear power and lignite. It is indeed more cost-effective from a systems point of view to use these technologies to generate electricity rather than to use them to provide upwards reserves. More expensive generation technologies (gas, biomass, and hydropower) see their production diminish accordingly as illustrated by **Figure *9***.

[15] The following countries currently adopt suboptimal FCR procurement practices: BE, EE, ES, FR, HR, IT, LT, LV, PT, SI, SK, UK. The following countries currently adopt suboptimal aFRR procurement practices: EE, FR, LT, LV, UK. Source: “Electricity Market Functioning: Current Distortions, and How to Model Their Removal”, COWI (2016).

Figure 9 - Impact of Sub-option 1b on the day-ahead dispatch of electricity

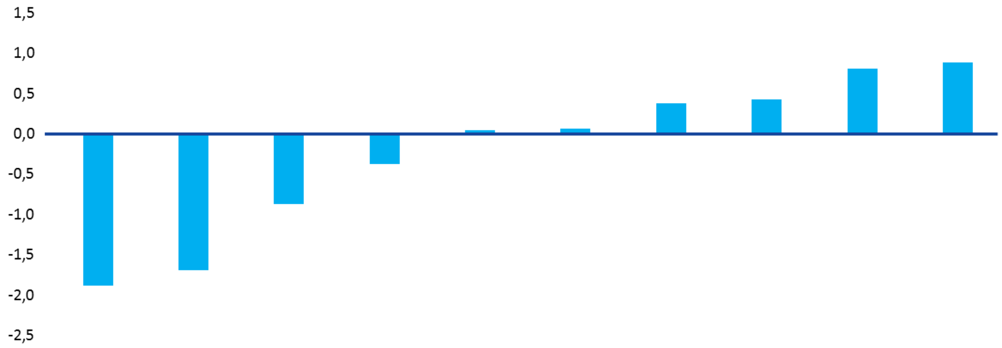


	Gas	Hydro	Biomass (incl. waste)	Lignite	Nuclear
Impact (TWh)	-30	-5	-5	+5	+25
Sub-option 1a production (TWh)	545	625	80	275	775

<u>EU-wide intraday market coupling</u>

Finally, Sub-option 1b assumes that intraday markets are coupled across Europe. This measure allows all interconnections to adjust their flows in intraday up to h-1 (implicit auctions) rather than h-4 in the currently non-coupled regions (EPEX, Nordpool and MIBEL intraday markets are assumed to be coupled in all options). As a consequence, when facing an imbalance in the intraday market, the power system can avoid using flexible but expensive local resources and instead use cheaper resources available cross-border. The impact of fully coupling the EU intraday markets on the intraday dispatch of electricity is illustrated in **Figure *10***.

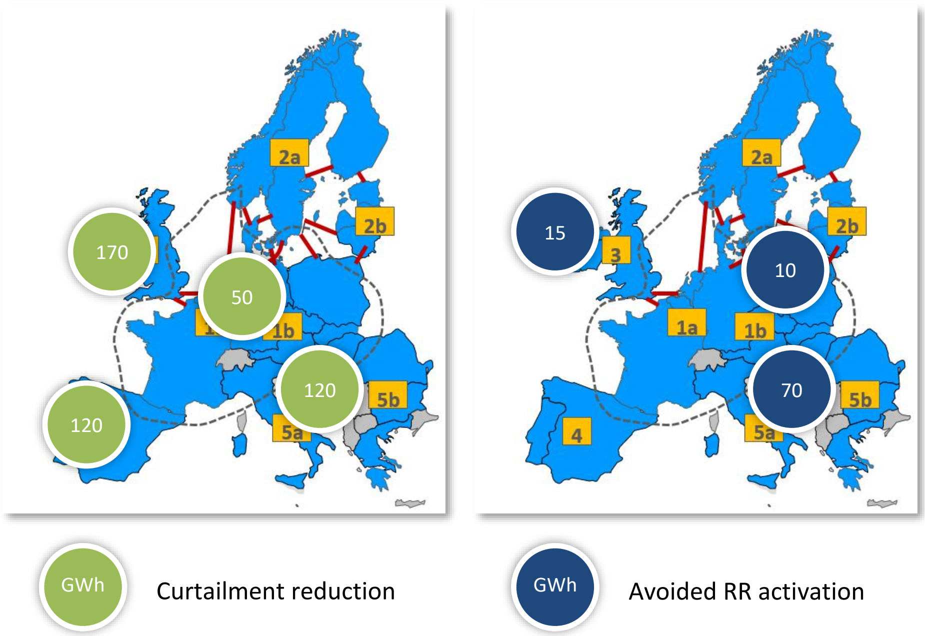
Figure 10 - Impact of Sub-option 1b on the intraday dispatch of electricity



	Hydro	Biomass	Gas	Oil	Waste	Solar	Lignite	Wind	Nuclear	Coal
Impact (GWh)	-1 900	-1 700	-900	-400	+50	+100	+400	+400	+800	+900

The further flexibility introduced by coupling EU intraday markets allows the power system to better react to deviations with respect to the day-ahead programme. In particular, curtailment is found to be reduced (better reaction to RES generation underestimation) and activations of replacement reserves are found to be less frequent (better reaction to demand underestimation). Wind and solar power are found to be better integrated not only in the newly coupled regions, but all across Europe as can be read from **Figure *11***.

Figure 11 - Impact of Sub-option 1b on curtailment and replacement reserves activations



<u>Summary</u>

All the policy measures introduced in Sub-option 1b aim at better interconnecting short-term markets, in particular by making better use of interconnection capacity.

The decrease of CO_2 emissions in Sub-option 1b with respect to Sub-option 1a is mainly driven by the replacement of gas generation by nuclear power due to the removal of suboptimal reserve procurement practices and the decrease of reserve needs.

In summary, the policy measures introduced in Sub-option 1b result in a reduction of the annual costs of around 10% or 8.6 B€. **Table *8*** shows how each of the considered timeframes (day-ahead, intraday, and balancing) contribute to these savings.

Table 8 - Key figures for MDI Sub-option 1b

Indicator	Baseline	Sub-option 1a	Sub-option 1b
Cost day-ahead (B€)	82.5	76.9	73.5
Cost intraday (B€)	1.4	0.9	1.2
Cost balancing (B€)	- 0.5	- 0.3	0.1
of which upwards	0.7	0.5	0.7
of which downwards	- 1.2	- 0.8	- 0.6
Total costs (B€)	83.4	77.5	74.8
Savings (B€)	-	5.9	8.6
Load payment (B€)	278	293	262
Weighted average price (€/MWh)	79	83	74
Energy (TWh)	3620	3610	3600
CO_2 emissions (Mt)	555	615	605

One can note that the weighted average day-ahead price decreases in Sub-option 1b due to the better exploitation of resources. The increase of the price associated with the removal of priority dispatch in Sub-option 1a is more than compensated for. The regional impacts are shown in **Table *9***.

Table 9 – Impact of Sub-option 1b on weighted average day-ahead prices

Weighted average day-ahead prices (€/MWh)	Region 1	Region 2	Region 3	Region 4	Region 5
Sub-option 1a	91	97	75	53	72
Sub-option 1b	77	82	74	55	71
Relative savings	15%	16%	2%	-4%	2%

5.3. SUB-OPTION 1c - PULL ALL FLEXIBLE RESOURCES INTO THE MARKET

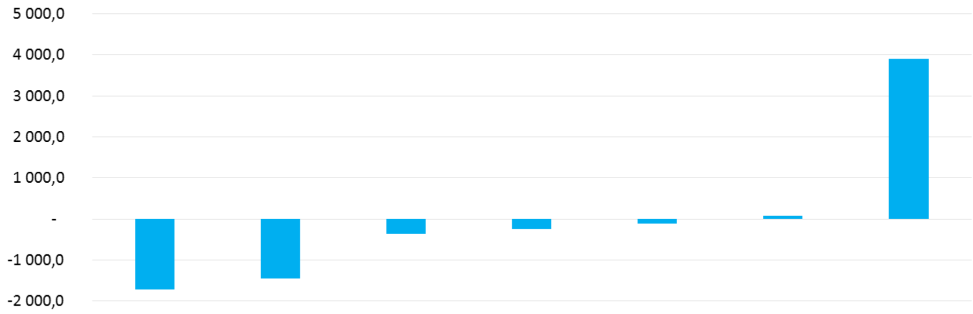
The measures introduced in this policy package aim at pulling all flexible resources (RES, DSR) into the market. Since all the measures discussed in Section 4.4 are introduced simultaneously, one can only observe the collective impact of the policy package. However, some of the impacts can be understood as predominantly resulting from the introduction of a given policy measure. These impacts are discussed below.

Pulling RES and further DSR into the reserve markets

In Sub-option 1c, further flexibility resources can access to reserve markets: RES capacities (wind, PV, run-of-the-river), waste and more DSR resources, such as storage-based DSR (water heating, electric vehicles charging) or other DSR (cooling, heating), can participate in reserve procurement.

Figure *12* presents the impact of Sub-option 1c on the portfolio of upwards active power reserves. DSR and variable RES are found to replace more expensive resources such as gas-fired plants and hydropower.

Figure 12 - Impacts of Sub-option 1c on the upwards active power reserve procurement

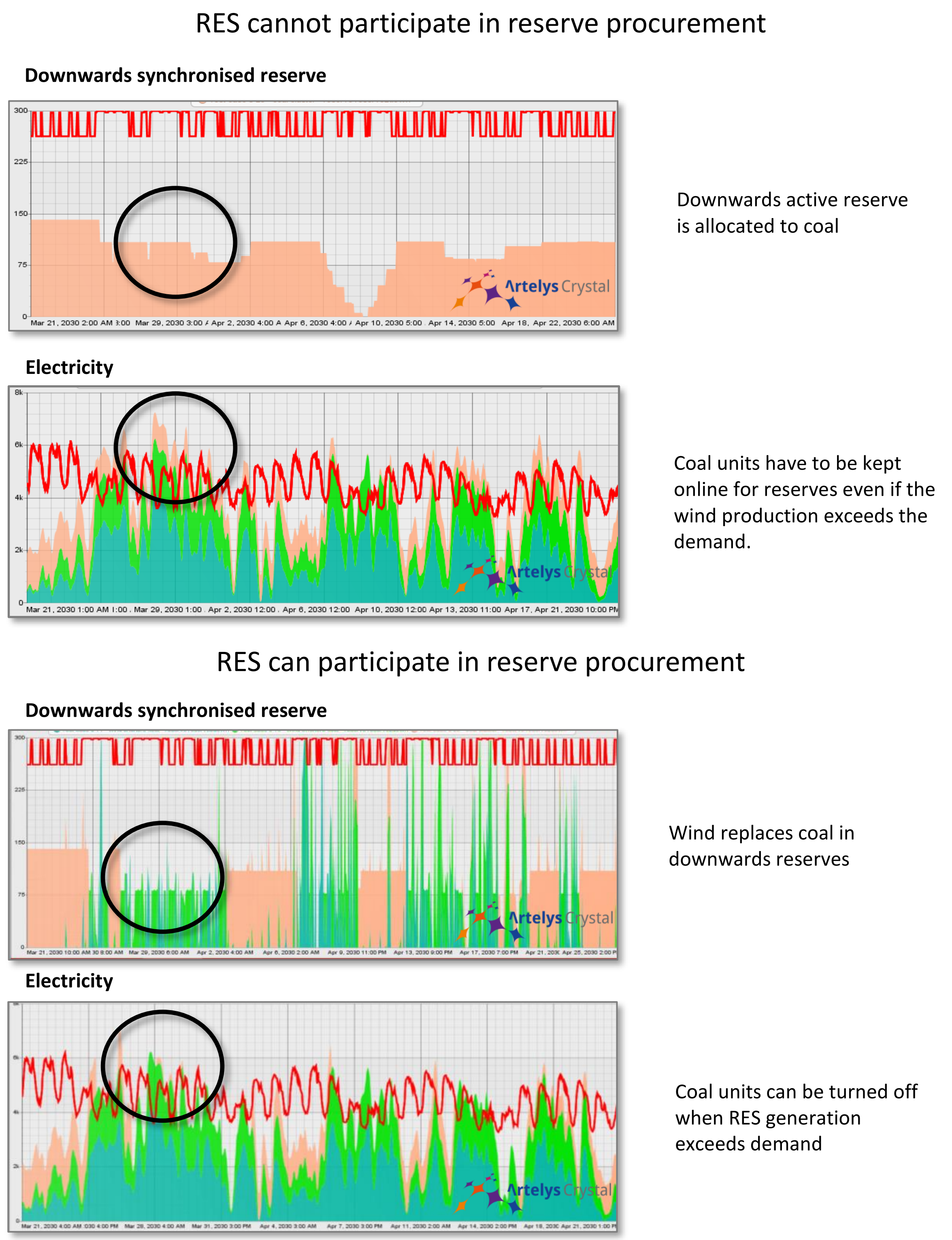


	Gas	Hydro	Coal	Biomass	Lignite	vRES	DSR
Impact (MW)	-1 700	-1 450	-350	-250	-100	+150	+3 900
Sub-option 1b reserves (MW)	2 600	6 600	800	1 000	200	0	0

The day-ahead dispatch of electricity is only marginally impacted by the policy measures introduced in Sub-option 1c. One of the impacts is the slight decrease of the production of coal power plants (6 TWh, corresponding to a 2% decrease) which is partly explained by the ability for RES to provide reserves.

This behaviour is illustrated by **Figure *13***. The demand for electricity and the one for reserves are represented by the solid red lines, the green areas represent onshore and offshore wind power, and the orange area represents coal units. When RES cannot participate in the reserve procurement process, coal units may have to be kept online even at times when the RES production (wind in this case) exceeds the demand in order to be able to provide downwards regulation. The lower part of the figure shows the impact of the participation of RES in the reserves. In particular, at times when wind power exceeds the demand, the system can choose not to start any coal units (they are not needed to maintain the balance of the system), and to use RES to provide downwards reserves instead of coal.

Figure 13 - Impact of RES participation on coal unit commitment



<u>Summary</u>

All the policy measures introduced in Sub-option 1c aim at pulling further flexible resources into the market. In particular, further DSR and RES can participate in the reserve procurement process, effectively displacing more expensive resources such as coal.

In summary, the policy measures introduced in Sub-option 1c result in a reduction of the annual costs of around 11% or 9.5 B€. **Table *10*** shows how each of the considered timeframes (day-ahead, intraday, and balancing) contribute to these savings.

Table 10 - Key figures for MDI Sub-option 1c

Indicator	Baseline	Sub-option 1a	Sub-option 1b	Sub-option 1c
Cost day-ahead (B€)	82.5	76.9	73.5	72.7
Cost intraday (B€)	1.4	0.9	1.2	1.1
Cost balancing (B€)	- 0.5	- 0.3	0.1	0.1
of which upwards	0.7	0.5	0.7	0.7
of which downwards	- 1.2	- 0.8	- 0.6	- 0.6
Total costs (B€)	83.4	77.5	74.8	73.9
Savings (B€)	-	5.9	8.6	9.5
Load payment (B€)	278	293	262	253
Weighted average price (€/MWh)	79	83	74	72
Energy (TWh)	3620	3610	3600	3590
CO_2 emissions (Mt)	555	615	605	600

5.4. OPTION 2 - FULLY INTEGRATED EU MARKET

The measures introduced in this policy package aim at fully integrating the European power markets. Since all the measures discussed in Section 4.5 are introduced simultaneously, one can only observe the collective impact of the policy package. However, some of the impacts can be understood as predominantly resulting from the introduction of a given policy measure. These impacts are discussed below.

<u>EU-wide dimensioning of frequency restoration reserves</u>

In Option 2, reserves are assumed to be dimensioned and procured at an EU level. This further reduces FRR needs, as is shown in **Table *11***. Reserve needs are found to be 63% lower than in the baseline.

Table 11 - Reserve needs for Option 2 and comparison with baseline

Reserve needs (GW)		Baseline	Sub-option 1a	Sub-option 1b	Option 2
Active power	**Upwards**	16.7	16.7	11.5	9.5
	Downwards	16.2	16.1	11.0	9.0
mFRR	**Upwards**	23.5	17.4	10.2	5.8
	Downwards	23.2	15.6	9.6	5.3
Total		**79.6**	**65.8**	**42.3**	**29.6**
Reduction of reserve needs		-	17%	47%	63%

As was already the case in Sub-options 1b and 1c, in order to continue to be able to face the same imbalance risks with a lower level of reserves, TSOs in Option 2 would have to reserve interconnection capacity in order to be able to exchange balancing energy to balance their national power systems.

<u>EU-wide procurement of reserves</u>

As anticipated in the previous paragraph, the system has to find the optimal trade-off between (a) a local provision of reserves and a low reservation level of interconnection capacity and (b) a higher reliance on neighbouring countries for the provision of balancing energy in case of imbalance, which allows to use generation capacities to produce energy rather than reserves.

Table *12* highlights the interest of cooperation for upwards reserve since the level of reserve that is procured is very close to the EU needs, meaning that interconnections have to be reserved for upwards regulation. In contrast, for downwards reserves, the procured reserve is almost equal to reserve needs without cooperation. Downwards reserves being very cheap, interconnections are only marginally used for downwards balancing risk sharing so as to increase their availability for power exchanges. One should note that Option 2 also assumes that security margins can be decreased thanks to the assumed strengthened coordination level between TSOs. An increase of 5% of the interconnection capacity with respect to Sub-options 1b and 1c reflects this last assumption.

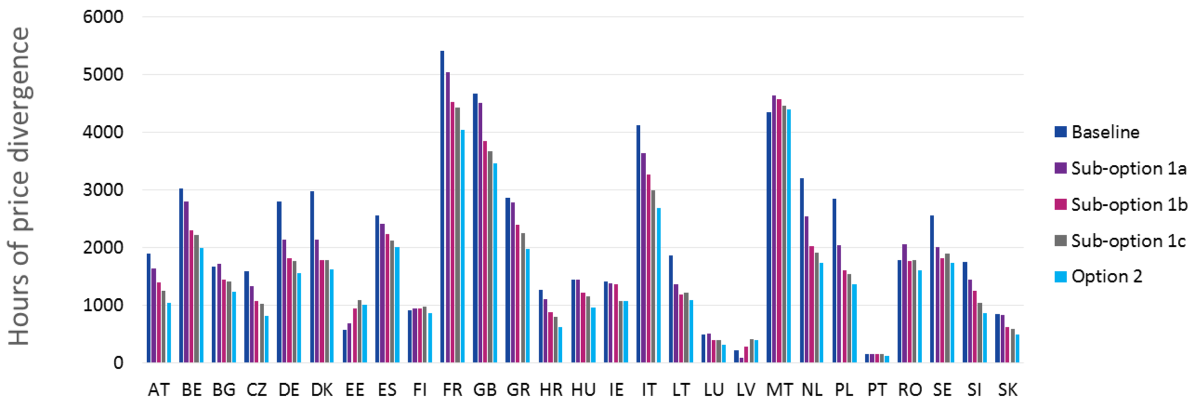
Table 12 – Trade-off between local provision of reserves and cooperation

Reserves (GW)		Needs to face same risk level	Procured in Option 2	EU needs (Option 2)
Active power	**Upwards**	16.4	9.5	9.5
	Downwards	15.1	14.8	9.0
mFRR	**Upwards**	17.4	6.0	5.8
	Downwards	15.6	15.5	5.3
Total		**64.5**	**45.8**	**29.6**

<u>Price convergence</u>

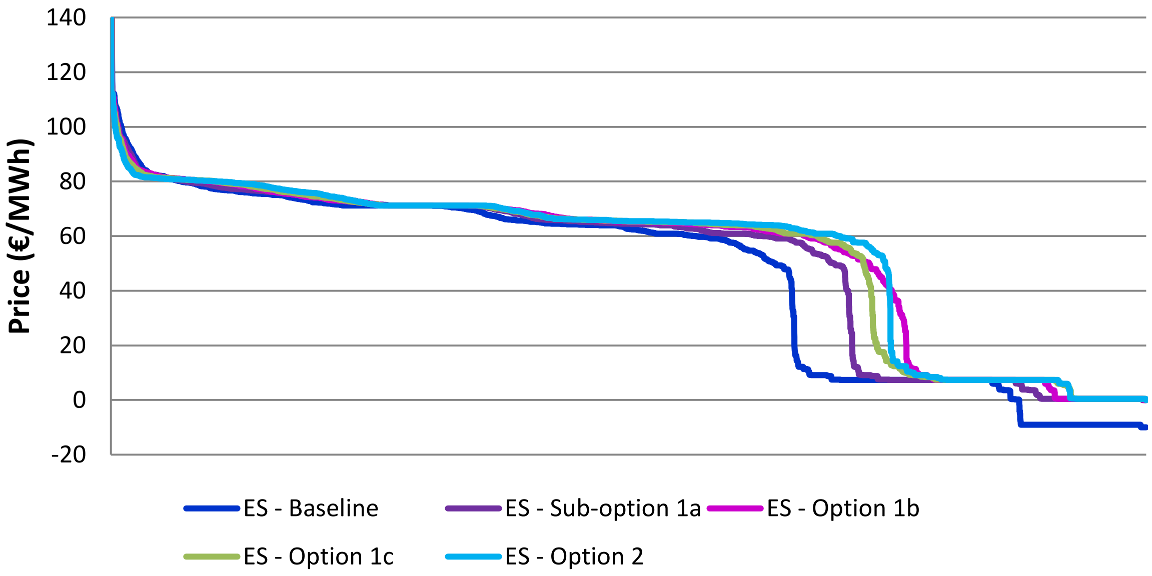
In addition to an overall reduction of costs and weighted average day-ahead cost of electricity, Option 2 tends to further decrease price divergence over Europe since markets are better interconnected and cross-border transmission capacities are better exploited. **Figure *14*** illustrates how the number of hours of price divergence evolves for each of the MDI options. The number of hours of price divergence for a given country is computed as the average over neighbours of the number of hours of price divergence.

Figure 14 - Number of hours of price divergence per country



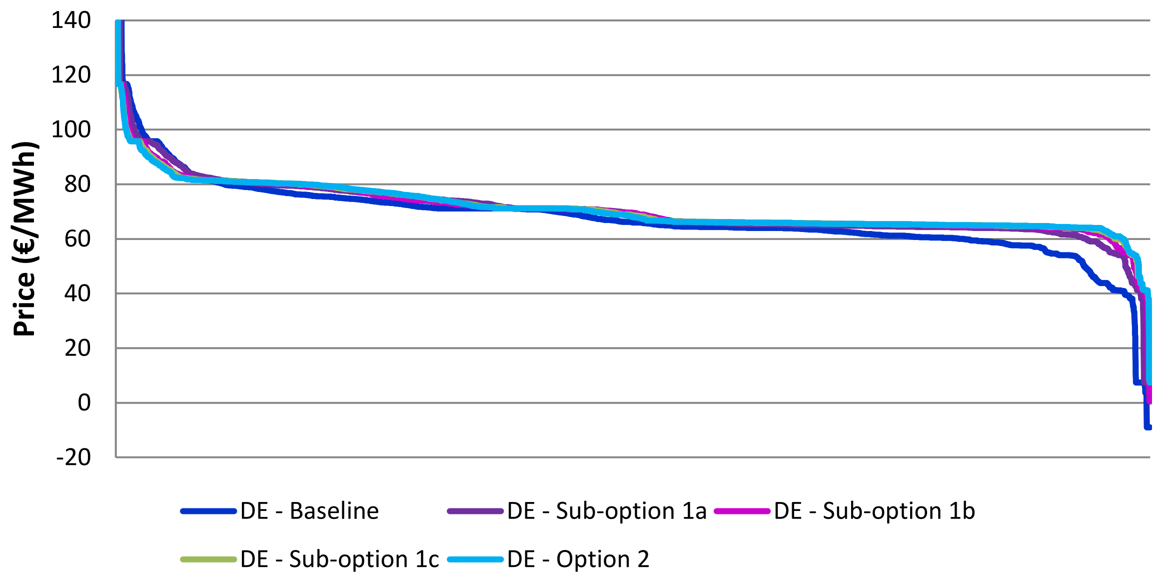
The price convergence effect can also be observed by examining the price duration curves for each of the MDI options. In the case of relatively isolated countries such as Spain, one can see that the plateau between 60 and 80 €/MWh widens as policy measures are introduced. The removal of priority dispatch in Sub-option 1a (1.5 GW of biomass is located in Spain) results in an increase of the electricity price (see **Figure *3***). Further options result in an intensification of cross-border exchanges, which tend to harmonise the electricity prices.

Figure 15 - Price duration curve - Spain



In the case of well interconnected countries such as Germany, the effects on the day-ahead electricity prices are found to be almost negligible. In the case of Germany, the price duration curve is already almost flat in the baseline, thanks to its very central position in Europe. The same kind of qualitative behaviour can nevertheless be observed: the price duration curve flattens as policy measures are introduced, and price plateaux propagate across Europe.

Figure 16 - Price duration curve - Germany



<u>Summary</u>

All the policy measures introduced in Option 2 aim at fully integrating the EU power markets across all timeframes: day-ahead and intraday markets are coupled, while reserves are dimensioned and procured at an EU-level.

In summary, the policy measures introduced in Option 2 result in a reduction of the annual costs of around 13% or 10.6 B€. **Table *13*** shows how each of the considered timeframes (day-ahead, intraday, and balancing) contribute to these savings.

Table 13 - Key figures for MDI option 2

Indicator	Baseline	Sub-option 1a	Sub-option 1b	Sub-option 1c	Option 2
Cost day-ahead (B€)	82.5	76.9	73.5	72.7	72.4
Cost intraday (B€)	1.4	0.9	1.2	1.1	0.3
Cost balancing (B€)	- 0.5	- 0.3	0.1	0.1	0.1
of which upwards	0.7	0.5	0.7	0.7	0.7
of which downwards	- 1.2	- 0.8	- 0.6	- 0.6	- 0.6
Total costs (B€)	83.4	77.5	74.8	73.9	72.8
Savings (B€)	-	5.9	8.6	9.5	10.6
Load payment (B€)	278	293	262	253	246
Weighted average price (€/MWh)	79	83	74	72	70
Energy (TWh)	3620	3610	3600	3590	3590
CO_2 emissions (Mt)	555	615	605	600	600

6. CONCLUSION

This study presents the impacts associated with the four policy packages designed by the European Commission to reduce the current inflexibility, better interconnect short-term markets, to pull further flexible resources into the market, and to fully integrate the EU power markets.

The key impacts of the four policy options are summarised in **Figure *17***, which also indicates an estimate of the corresponding savings (in B€). The main assumptions used in this work are presented in Section 4.

Figure 17 - Main impacts of the MDI options

Sub-option 1a	Sub-option 1b	Sub-option 1c	Option 2
Balancing responsibility 30% less mFRR to procure **Priority dispatch** Important impact on biomass dispatch (-85%) **Curtailment** Reduction of 35%	**Regional cooperation** 20 to 55% less FRR to procure depending on region (1.2 B€) **Regional cooperation** Reservation of 5.8% of cross-border transmission capacity **Optimal reserve procurement and asymmetric bids** 1.5 B€ savings	**Access to market** DSR and wind participate to reserves	**EU-wide cooperation** Further reduction of FRR to be procured, but further competition for interconnection capacity
Savings **5.9 B€** (Compared to Baseline)	**Savings:** **2.7 B€** (Compared to 1a)	**Savings:** **0.9 B€** (Compared to 1b)	**Savings:** **1.1 B€** (Compared to 1c)

This study has focused on the benefits of the introduction of policy options and has not attempted to capture the costs of implementing these measures (e.g. new roles for existing bodies such as Regional Security Coordinators, introduction of new bodies, rollout of smart meters, etc.). We however expect costs to be significantly lower than the estimated savings generated by the considered policy options. Public acceptance and legal feasibility have not been considered in this study.

Overall, Sub-option 1a, which consists of the most easily achievable policy measures, results in annual savings of 5.9 B€ compared to current market arrangements. Regional cooperation and the removal of suboptimal reserve procurement practices results in further savings of 2.7 B€. Increasing the participation of the demand-side in the short-term operations of the power system and allowing RES to provide reserves further reduces the system costs by around 0.9 B€. Finally, Option 2, which would significantly reshape the organisation of the European power system, generates savings of the order of 1.1 B€ compared to Sub-option 1c.

One should however note that policy measures do not have an intrinsic value: their impact can depend on the system to which they are applied as is illustrated in Appendix B. However, the analysis shows that the differences generated by changing the order in which measures are introduced tend to be relatively minor and not to modify our main conclusions.

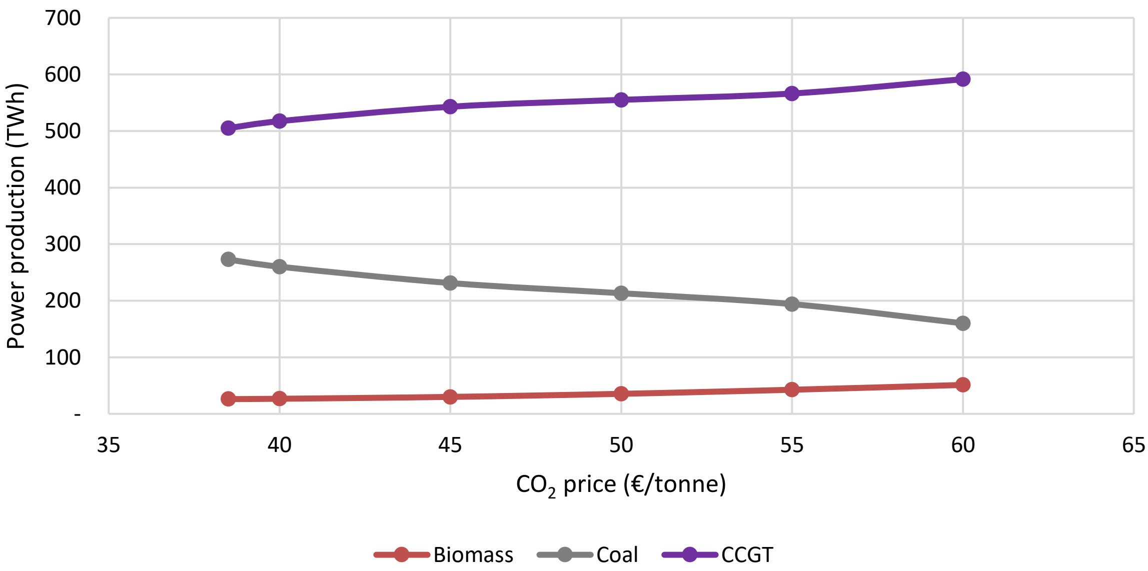
Appendix A Sensitivity analysis – Price of CO_2

Removing priority dispatch in Sub-option 1a negatively impacts the CO_2 emissions since biomass units produce around 85% less in this option than in the baseline. Since it is replaced by more CO_2-intensive technologies such as gas and coal (see **Figure *2***), the CO_2 emissions are found to increase by around 60 Mt compared with the baseline.

In this Appendix, we examine under what conditions (i.e. what level of CO_2 price), the system would be incentivised to adapt its utilisation of the generation portfolio so that Sub-option 1a does not result in any increase of CO_2 emissions compared to the baseline.

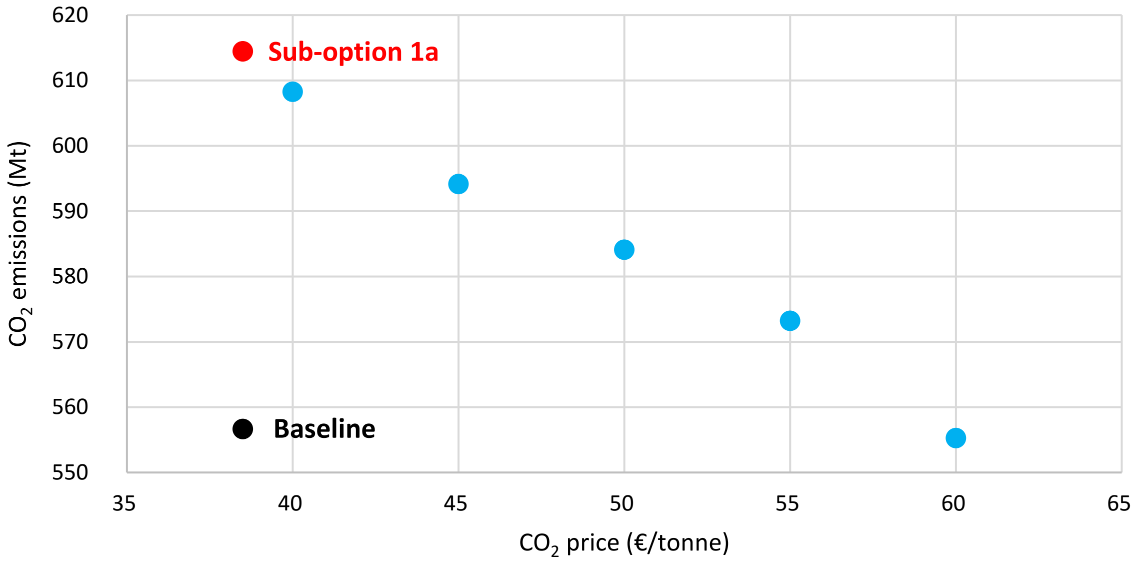
Sub-option 1a has therefore been simulated for different levels of CO_2 prices. The CO_2 price increase triggers a progressive shift from coal to CCGTs and biomass as can be seen from **Figure *18***. As one increases the CO_2 price from the EuCo27 value (38.5€/tonne) to 60 €/tonne, the coal production decreases by around 110 TWh, while the production levels of CCGTs and biomass are found to increase by 85 TWh and 25 TWh respectively.

Figure 18 - Influence of CO_2 price on coal to gas switching in Sub-option 1a



A CO_2 price of 60 €/tonne is found to decrease emissions by around 60 Mt, as can be read from **Figure *19***, which is roughly equal to the CO_2 emissions increase caused by the removal of priority dispatch for biomass. In other words, with an increase of CO_2 price of around 20 €/tonne, the biomass production decreases less acutely and enough generation switches from coal to gas to ensure the CO_2 emissions remain unchanged when removing priority dispatch.

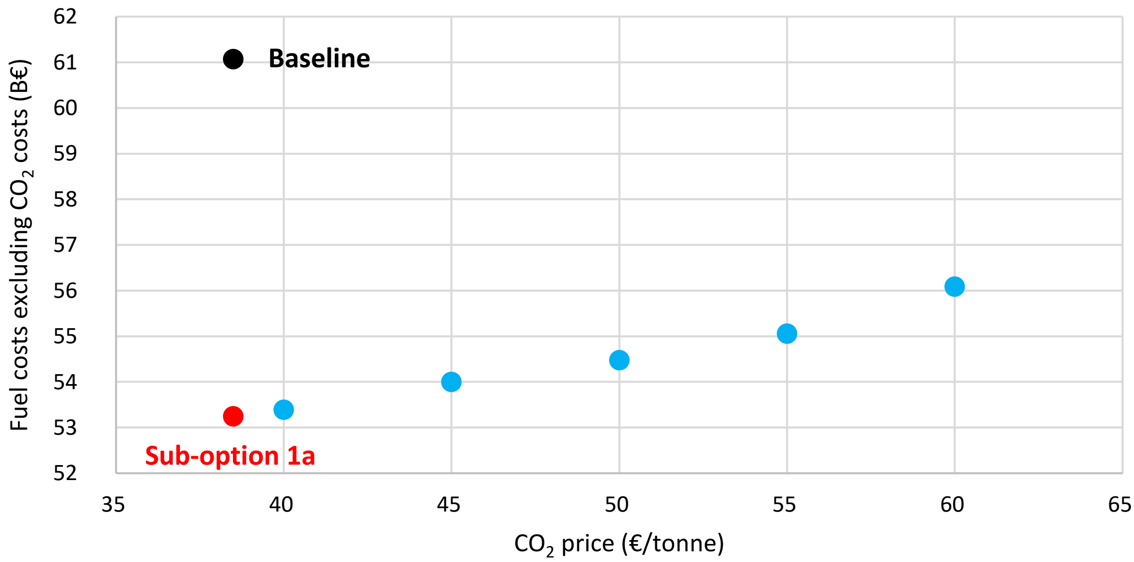
Figure 19 - Influence of CO_2 price on CO_2 emissions in Sub-option 1a



Increasing the CO_2 price has an influence on the fuel costs of the power system since the amount of coal consumption decreases while the amount of gas consumption increases. Since producing electricity with gas is more expensive than doing so with coal, the system fuel costs increase when increasing the CO2 price, as can be read from **Figure *20***.

In particular, it is found that priority dispatch (i.e. going from Sub-option 1a to the baseline) is less efficient a measure to decrease emissions than increasing the CO_2 price when measured in terms of primary energy costs.

Figure 20 - Impact of CO_2 price on fuel costs in Sub-option 1a



Appendix B Sensitivity analysis – Value of Sub-option 1c

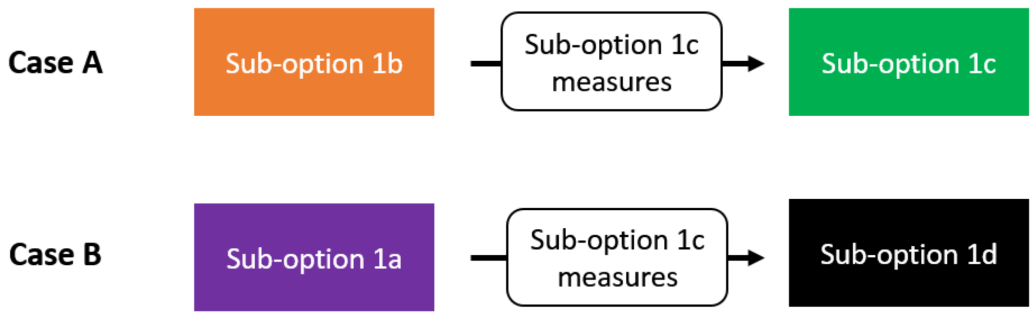
The goal of this Appendix is to present the sensitivity of the benefits attributed to policy measures to the order in which they are introduced. The total benefits remains independent of the order in which measures are introduced. The analysis is restricted to the day-ahead timeframe.

The two possibilities explored below are:

- **Case A**: the policy measures of Sub-option 1b are introduced before the policy measures of Sub-option 1c. Case A corresponds to the order in which policy measures are introduced in this report.

- **Case B**: the policy measures of Sub-option 1c are introduced before the policy measures of Sub-option 1b. The policy measures of the new policy option Sub-option 1d are those of Sub-options 1a and 1c.

Figure 21 - Impact of Sub-option 1c measures in Cases A and B



In Case A, the savings associated with the introduction of the Sub-option 1c measures are found to be of the order of 0.8 B€ as can be read from **Table *14*** (difference between Sub-options 1c and 1b) In contrast, in Case B, the savings associated with the Sub-option 1c measures are found to be of the order of 1.1 B€ (difference between Sub-options 1d and 1a).

Table 14 – Day-ahead costs of MDI options and of Sub-option 1d

Indicator	Sub-option 1a	Sub-option 1b	Sub-option 1c	Sub-option 1d
Cost day-ahead (B€)	76.9	73.5	72.7	75.8
CO_2 emissions (Mt)	615	605	600	610

This analysis demonstrates that, as one could expect, policy measures do not have an intrinsic value, but depend on the configuration of the system to which they are applied. The same is true for other characteristics such as CO_2 emissions reductions, even if, in this case, the impact of Sub-option 1c is found to be the same in Cases A and B.

In summary, the order in which options are introduced can slightly change their valuation, but does not modify the main conclusions of this report.

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