EUROPEAN
COMMISSION

Brussels, 30.11.2016
SWD(2016) 410 final

PART 1/5

COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT

Accompanying the document

Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast)

Proposal for a Regulation of the European Parliament and of the Council on the electricity market (recast)

Proposal for a Regulation of the European Parliament and of the Council establishing a European Union Agency for the Cooperation of Energy Regulators (recast)

Proposal for a Regulation of the European Parliament and of the Council on risk preparedness in the electricity sector

{COM(2016) 861 final}
{SWD(2016) 411 final}
{SWD(2016) 412 final}
{SWD(2016) 413 final}

Abstract of the Impact Assessment of the Market Design Initiative

I. POLICY CONTEXT AND KEY CHALLENGES

The Energy Union framework strategy puts forward a vision of an energy market 'with citizens at its core, where citizens take ownership of the energy transition, benefit from new technologies to reduce their bills, participate actively in the market, and where vulnerable consumers are protected'.

Well-functioning energy markets that ensure secure and sustainable energy supplies at competitive prices are essential for achieving growth and consumer welfare in the European Union and hence are at the heart of EU energy policy.

To live up to this vision, a series of legislative proposals have been prepared, following the objectives of secure and competitive energy supplies and building on the EU's 2030 climate commitments reconfirmed in Paris last year.

The electricity sector will be one of the main contributors to decarbonise the economy. Currently, 27.5% of Europe's electricity is produced using renewable energy and the modelling shows that close to half of our electricity will come from renewables by 2030. With increasing use of electricity in sectors like transport or heating and cooling, traditionally dominated by fossil fuels, it is ever more important to further increase the share of renewable energies in electricity and to unlock flexible demand, generation and storage solutions.

A new regulatory framework is needed to address these challenges and opportunities. The new proposals for a revised Renewable Energy Directive and for a new Market Design will precisely do this, by deepening integration of the internal energy market, empowering consumers, stepping up regional and EU-wide cooperation and providing the right signals for investment, thus ensuring secure, sustainable and competitive electricity systems.

A successful transition of the energy system delivering on the ambition to become world leader in renewables will require substantial investment in the sector, and in particular investments in low-carbon generation assets as well as network infrastructure. This requires a revised Emissions Trading System in order to address the current surplus of allowances and to deliver a strong investment signal to reach 40% greenhouse gas emissions reductions by 2030, but also specific rules to complement market revenues if those are not sufficient to attract investments in renewable electricity. In addition, measures to promote renewable energies in sectors like transport or heating and cooling are also crucial. Reaching the 2030 framework targets and achieving an Energy Union will be underpinned by a strong Energy Union governance, which will ensure the necessary ambition level in an iterative dialogue between the Commission and all Member States. Finally, a successful transition of the energy system will also require continued commitment and support for infrastructure development both locally as well as across borders.

At the same time the transition will only be successful if consumers are given the information, opportunities and rewards to actively participate in it. The availability of new technologies that allow consumers to both consume electricity in a smarter way as well as produce it themselves at costs which are more and more competitive opens up manifold possibilities. What is still needed to fully reap these opportunities is the appropriate regulatory framework accompanying the digital transformation and technological development that will empower consumers to take part in the energy transition by becoming active market participants. Empowering consumers in this way will also contribute to a more efficient use of energy and is therefore an integral part of implementing the efficiency first principle.

Finally, the EU will only be able to manage the energy transition successfully and cost-effectively in a more deeply integrated internal electricity market. Only a more competitive and better interconnected market will allow Europe to drive cost-efficient investment and in particular to integrate the rising share of renewable energy production in a cost-efficient and secure manner into the system, profiting fully from complementarities between Member States and broader regions.

Such a deeply integrated and competitive market is also a key building block for guaranteeing security of supply and policies and mechanisms intended to reach this objective should follow a cooperative logic. National security of supply policies need to be better coordinated and aligned. This will ensure that Member States are duly prepared to tackle possible crisis situations, in particular those that affect several countries at the same time.

The present package of legislative measures directly contributes to the Energy Union dimensions of energy security, solidarity and trust, a fully integrated internal energy market as well as decarbonisation of the economy, while also indirectly contributing to the other two.

II. LESSON LEARNED AND PROBLEM DEFINITION

Three consecutive legislative packages have transformed what used to be fragmented energy markets in Europe into a more integrated Internal Electricity Market, thus increasing competition. However, Europe's energy markets are undergoing further profound changes.

The transition towards a low-carbon electricity production poses a number of challenges for the secure and cost-effective organisation and operation of Europe’s power grids and electricity markets. The increasing penetration of variable and decentralised renewable energy – driven *inter alia* by the EU’s goals for climate change and energy in line with the 2020 and 2030 targets – **requires the electricity sector to be operated more flexibly and efficiently**.

Today, most new installed capacity is based on wind and solar power which are inherently more variable and less predictable when compared to conventional sources of energy (predictable central, large-scale fossil fuel-based power plants) or flexible renewable energy technologies (e.g. biomass, geothermal or hydropower). By 2030, this trend is expected to be ever more pronounced. As a result, there will be times when variable renewables could cover a very large share - even 100% - of electricity demand and times when they only cover a minor share of total consumption. The overall electricity supply and demand needs to be in balance in physical terms at any given point in time (including production or storage of electricity). This balance is a precondition for the secure operation and stability of the electricity grid, thus avoiding the risk of black-outs.

Current market arrangements do not adequately incentivize all market participants – including renewable energy generation - to adjust their portfolios by revising production and consumption plans on short notice. The manner in which the trading of electricity is arranged and in which the methods for allocating the network capacity to transport electricity are organized, allow only for efficient trading of electricity in timeframes of one or more days ahead of physical delivery. Yet, the increasing penetration of variable renewable sources of electricity ('RES E') requires efficient and liquid short-term markets that can operate as close to real time as possible – until very shortly before the time of physical delivery (i.e. the moment when electricity is consumed). Indeed, most renewable generation can only be accurately predicted shortly before the actual production (due to weather uncertainties). Flexibility is essential to deal effectively with an increased share of variable renewable generation. Besides, these markets do not fully take into account possible contribution of cross-border resources.

Retail markets for energy in most parts of the EU suffer from persistently low levels of competition, consumer choice and engagement. In spite of falling prices on wholesale markets, retail prices have risen steadily for households as a result of significantly increased network charges, taxes and levies in recent years. Market concentration remains generally high due to persisting barriers to new entrants. Switching related fees such as contract termination charges continue to constitute a significant financial barrier to consumer engagement. In addition, the high number of complaints related to billing suggests that there is still scope to improve the comparability, clarity and accuracy of billing information.

Despite technical innovations that allow consumers to better and more easily manage their energy use – smart grids, smart homes, rooftop solar panels and storage, for example – consumers are not sufficiently able to actively participate in electricity markets and match demand with supply during peak times, particularly through demand-response. This is because households and businesses often have scarce knowledge and little or no incentive to change the amount of electricity they use or produce in response to changing prices in the markets. Indeed, a host of issues such as a slow roll out of fully functional smart metering systems, regulated prices, lacklustre competition between retailers and an increasing portion of fixed charges in energy bills mean that real-time price signals are usually not passed on to final consumers.

In some Member States, up to 90% of renewable electricity generation is connected at distribution level, putting more pressure on distribution system operators ('DSOs') to actively manage their grids and to efficiently adjust to the increasing share of variable and decentralized renewable electricity injected into their networks. However – in contrast to transmission system operators ('TSOs') – the current regulatory framework does not always provide appropriate tools to DSOs to do this, resulting in network charges that are often higher than they could be for end consumers. Ensuring that all DSOs become more flexible would create a level playing field for the deployment of renewable generation that would make attaining the EU's climate and energy objectives easier.

The deployment of information technology offers the possibility to address these issues, facilitating the development of new services, improving consumer's comfort and making the market more contestable and efficient. However, to fully benefit from the digitalisation of the electricity market we need a non-discriminatory data management framework that makes the right information immediately available to the right market actors, while at the same time ensuring a high level of data protection.

With regard to consumer protection, there is a need to ensure that the move towards more efficient retail markets does not lead to any group of consumers being left behind. In particular, rising energy poverty as well as a lack of clarity on the most appropriate means of tackling consumer vulnerability and energy poverty can hamper the further deepening of the internal energy market.

In the current context, wholesale electricity prices have been decreasing due to number of coinciding drivers: a decline in primary energy prices, a surplus of carbon allowances and an overcapacity of power generation facilities in some regions of the EU caused by a drop in electricity demand, rising investments in renewables driven by EU policies and increased sharing of resources among Member States through market coupling.

For most regions in Europe, **current electricity wholesale prices do not indicate the need for new investments into electricity generation**. However, in the current market arrangement, prices often do not reflect the real value of electricity due to regulatory failures such as the lack of scarcity pricing and inadequately delimited price (or bidding) zones. These regulatory failures, taken together with the increasing penetration of electricity generated from renewable sources with low operating costs, affect the remuneration of conventional electricity generation units that operate less often but contribute to providing security and flexibility to the system – alongside non-conventional flexible generation, interconnections, storage and demand response.

In light of the 2030 objective for renewable energy, considerable new investment in electricity generation capacity will be required. The largest part will be provided by variable renewable generation, complemented to a certain extent by more predictable, flexible, less carbon-intensive forms of power generation. Independently of current overcapacities, there are growing concerns in some areas of Europe that current average wholesale prices may not provide appropriate signals for the necessary investments into future generation or for keeping sufficient capacity in the market. A number of Member States anticipate inadequate generation capacity in future years and introduce capacity mechanisms at national level to support investment in capacity and ensure system adequacy (i.e. the ability of the electricity system to serve demand at all times). **When uncoordinated** and designed without a proper assessment of the appropriate level of supply security, **capacity mechanisms may risk affecting cross-border trade, distorting investment signals,** affecting thus the ability of the market to deliver any new investments in conventional and low-carbon generation, **and strengthening market power** of incumbents by not allowing alternative providers to enter the market.

Despite best efforts to build an integrated and resilient power market, crisis situations can never be excluded. The potential for crisis situation increases with climate change (e.g. extreme weather conditions) and the emergence of new areas that are subject to criticalities such as malicious attacks and cyber-threats. Such crises tend to often have an immediate cross-border effect in electricity. Where systems are interconnected, incidents that start locally can rapidly spread beyond borders and crisis situations might also affect several Member States at the same time (e.g. prolonged heat waves or cold spells).

Today, **risk assessments as well as plans and actions for dealing with electricity crisis situations focus on the national context only** and there is insufficient information-sharing and transparency across Member States. In addition, there are different views on what is to be considered as a risk to security of supply. In an increasingly inter-connected electricity market, the lack of common approach and coordination can seriously imperil security of supply across borders and dangerously undermine the functioning of the internal electricity market.

In addition, missing opportunities to exchange energy with neighbours remains a key obstacle to the internal energy market. Even where interconnectors are in place, they often remain unused due to a lack of coordination between Member States. Rules are therefore needed that ensure that the use of interconnection is not unduly limited by national interventions.

Based on the above-mentioned shortcomings and underlying drivers, the present impact assessment has identified four key problem areas that are addressed in the proposed initiative: **i) the current market design is not fit for integrating an increasing share of variable, decentralised generation and for reaping the potential of technological developments; ii) uncertainty about sufficient future generation investments and uncoordinated capacity mechanisms; iii) Member States do not take sufficient account of what happens across their borders when preparing for and managing electricity crisis situations; and iv) as regards retail markets, there is a slow deployment and low levels of services and poor market performance are wide-spread in the EU.**

III. SUBSIDIARITY

Article 194 of the Treaty of the Functioning of the EU consolidated and clarified the competences of the EU in the field of energy and is the legal basis of the current proposal.

Electricity markets have become more integrated and interdependent physically, economically and from a regulatory point of view, due to increasing cross-border electricity trade, growing share of renewable energy sources and more interconnections in the European electricity grid. The challenges can no longer be addressed as effectively by individual Member States. New frameworks to further integrate the internal energy market and improve the conditions for competition while at the same time adjusting to the decarbonisation targets and ensuring a more coordinated policy response to security of supply, can most effectively be achieved at European level.

IV. SCOPE AND OBJECTIVES

Against this background and in line with the Union's policy on climate change and energy, the general policy objective of the present initiative is to make electricity markets more secure, efficient and competitive, while ensuring that electricity is generated in a sustainable way and remains affordable to all consumers. The present impact assessment reflects and analyses the need and policy options for a possible revision of the main framework governing electricity markets and security of supply policies in Europe.

There are four specific objectives: i) adapt the market design for the cost effective operation of variable and often decentralised generation, taking into account technological developments; ii) facilitate investments in generation capacity in the right amount and type of resources for the EU: iii) improve Member States' resilience on each other in times of system stress and reinforce their coordination and cooperation regarding crisis situations; and iv) address the root causes of weak competition on energy retail markets and improve consumer protection and engagement.

Interlinkages with parallel initiatives

The proposed initiative is strongly linked to other energy and climate related legislative proposals brought forward in parallel, including the renewable energy package which covers a number of measures deemed necessary to attain the EU binding objective of reaching a level of at least 27% renewables in final EU energy consumption by 2030. The renewable energy directive has synergies with the present initiative, which seeks to adapt the current market design to the increasing share of variable decentralised generation and technological development and to create an environment conducive for investments in renewables.

In particular, the reflections on a revised Renewables Energy Directive will include framework principles on support schemes for market-oriented, cost-effective and more regionalised support to RES E up to 2030, in case Member States were opting to have them as a tool to facilitate target achievement. Conversely, measures aimed at the integration of RES E in the market, such as provisions on priority dispatch and access previously contained in the Renewables Directive are part of the present market design initiative. The Renewable Package also deals with legal and administrative barriers for self-consumption, whereas the present package addresses market related barriers to self-consumption.

Both the market design and renewable energy impact assessments come to the conclusion that the improved electricity market, supported through a revised Emission Trading System ('ETS'), could, under certain conditions, by 2030 deliver investments in the most mature low-carbon technologies (such as PV and onshore wind). However, until such conditions materialise, market-based support schemes will still be needed in order to provide investment certainty. Less mature RES E technologies, such as offshore wind, will likely need some form of support throughout the transitional period.

The Energy Union governance initiative also has synergies with the present initiative and will contribute to ensure policy coherence and reduce administrative impact. It will also streamline the reporting obligations by Member States and the Commission that are presently enshrined in the Third Package.

In general terms, energy efficiency measures also interact with the present initiative as they affect the level and structure of electricity demand. In addition, energy efficiency measures can alleviate energy poverty and consumer vulnerability. Besides consumer income and energy prices, energy efficiency is one of the major drivers of energy poverty. The provisions previously contained in the energy efficiency legislation on demand response, billing and metering will be set out in the present initiative.

The present initiative is furthermore consistent with the findings of the sector inquiry on capacity mechanisms. Pointing out that there is a lack of adequate assessment of the actual need for capacity mechanisms, the sector inquiry emphasizes that where needed capacity mechanisms need to be designed with transparent and open rules of participation that does not undermine the functioning of the electricity market, taking into account cross border participation.

The Commission Regulation establishing a Guideline on Electricity Balancing ('Balancing Guideline') is also closely related to the present initiative as it aims to harmonise certain aspects of the EU's balancing markets and to optimise cross-border usage. Indeed, efficient, integrated balancing markets are an important building block for the consistent functioning and flexibility of the market which in turn is needed for a cost effective integration of RES E into the electricity market.

V. DESCRIPTION OF POLICY OPTIONS AND METHODOLOGY

In assessing all possible options (ranging from non-regulatory to legislative policy options) the following approach was taken:

- Identification of a set of high level options for each problem area. Each of these high level options contains sub-options for specific measures;

- Assessment of each specific measure, comparing a number of options in order to select the preferred approach.

The following policy options have been considered:

Regarding Problem Area I: the need to adapt the market design to the increasing share of variable decentralised generation and technological developments,

Option 0+ (Non-regulatory approach) provides little scope for improving the market and the level-playing field among resources. Indeed, the current EU regulatory framework is limited in certain areas (e.g., balancing and intraday markets) and even non-existent for other areas (e.g., role of DSOs in data management). Besides, voluntary cooperation may not provide for the appropriate levels of harmonisation or certainty to the market and legislation. This option was therefore discarded.

Two possible paths going beyond the baseline scenario were however identified and assessed: (i) enhancing current market rules through EU regulatory action in order to increase the flexibility of the system, retaining to a certain extent the national operation of the systems (Option 1) and, (2) moving to a fully integrated approach via relatively far-reaching changing to the current regulatory framework (Option 2).

Option 1 of enhancing the current market rules comprises three different sub-options:

Option 1(a)	Creating a level-playing field among all generation technologies and resources and remove existing market distortions. It addresses rules that discriminate between resources and which limit or favour the access of certain technologies to the electricity grid (such as so-called 'must-run' provisions and rules on priority dispatch and access). In addition, all market participants would bear financial responsibility for the imbalances caused on the grid and all resources would be remunerated in the market on equal terms. Barriers to demand-response would be removed. Exemptions from certain regulatory provisions may, in some cases, be required, notably for certain small-scale installations and emerging technologies.
Option 1(b)	(In addition to sub-option (a)) Strengthening the short-term markets by bringing them closer to real-time in order to provide maximum opportunity to meet the flexibility needs and balance the market. The sizing of balancing reserves and their use would be harmonised in larger balancing zones in order to optimally exploit interconnections and cross-border exchange in shorter term markets.
Option 1(c)	(In addition to sub-option (a) and (b)) Pulling all flexible distributed resources concerning generation, demand and storage, into the market via proper incentives and a market framework better adapted to them. This would be based on smart-metering allowing consumers to directly react to price signals and measures to incentivise DSOs to manage their networks in a flexible and cost-efficient way.

Option 2 (fully integrated market) considers measures that would aim to deliver a truly integrated pan-European electricity market through the adoption of far-reaching measures changing the current regulatory framework.

Regarding Problem Area II: uncertainty about sufficient future generation investments and uncoordinated capacity mechanisms, four options were considered.

As regards Option 0+ (Non-regulatory approach), existing provisions under EU legislation are not sufficiently clear and robust to cope with the challenges facing the European electricity system. In addition, voluntary cooperation may not provide for appropriate levels of harmonisation across all Member States or certainty to the market. Legislation is needed in this area to address the issues in a consistent way. This Option was therefore discarded.

Various policy options going beyond the baseline scenario were assessed. They differ according to which extent market participants can rely on energy market payments. Each policy option also considers varying degrees of alignment and coordination among Member States at EU-level.

Option 1 (energy-only market without capacity mechanisms) builds upon Option 1(a) to 1(c) under problem area I and would be based on additional measures to further strengthen the internal electricity market. Under this option, it is assumed that European markets, if sufficiently interconnected and undistorted, can provide for the necessary price signals to incentivise investments in new generation thus also reducing the need for government interventions in support thereof. This option consists of improving price signals by removing price caps in order to allow scarcity pricing during peak time. At the same time, price signals could drive the geographical location of new investments and production decisions, via price zones aligned with structural congestion in the transmission grid.

Option 2 and 3 include the measures presented in Option 1, but allow capacity mechanisms under certain conditions and propose possible measures to better align them among Member States in order to avoid negative consequences for the functioning of the internal market. These options build on the European Commission's 'EEAG' state aid Guidelines and the Sector Inquiry on capacity mechanisms. In Option 2, capacity mechanisms are based on a transparent and EU-wide resource adequacy assessment carried-out by the European Network of Transmission System Operators for electricity ('ENTSO-E'). Such EU-wide assessment would also allow for effective cross-border participation. Additionally, Option 3 would provide for common design features for better compatibility between national capacity mechanisms and harmonised cross-border cooperation.

Under Option 4 based on regional or EU-wide generation adequacy assessments, entire regions or ultimately all EU Member States would be required to roll out capacity mechanisms on a mandatory basis. This option was found to be disproportionate and was discarded.

Regarding Problem Area III: the lack of coordination among Member States when preparing for and managing electricity crisis situations, five policy options ranging from the baseline scenario (Option 0) to the full harmonization and decision making at regional level have been identified.

Option 0+ (Non-regulatory approach). As current legislative provisions do not prescribe how Member States should prevent and manage crisis situations nor mandate any form of cross-border co-operation, better implementation and enforcement actions will be of no avail. In addition, whilst there is some voluntary cross-border cooperation in this area, it is limited to a few regional parts of the EU. This option was discarded.

Under Option 1 (Common minimum EU rules), Member States would have to respect a set of common rules and principles regarding crisis prevention and management, agreed at the European level ('minimum harmonisation'). Accordingly, non-market measures should only be introduced as a means of last resort, when duly justified. Member States would be obliged to address electricity crisis situations, in particular situations of a simultaneous crisis, in a spirit of co-operation and solidarity. Member States should inform each other and the Commission without undue delay when they see a crisis situation coming or when being in a crisis situation. Member States would be obliged to develop national Risk Preparedness Plans ('Plan') with the aim to avoid or better tackle crisis situations. Plans could be prepared by TSOs, but need to be endorsed at the political level. On cyber-security, Member States would need to set out in the Plan how they will prevent and manage cyberattack situations.

Option 2 (EU rules + regional cooperation) would include all common rules included in Option 1. In addition, it would put in place rules and tools to ensure that effective cross-border co-operation takes place in a regional and EU context. Thus, there would be a systematic assessment of rare/extreme risks at the regional level. The identification of crisis scenarios would be carried out by ENTSO-E in a regional context and tasks would be delegated to Regional Operation Centres (ROCs). For cybersecurity, the Commission would propose the development of a network code/guideline which would ensure a minimum level of harmonization in the energy sector throughout the EU. The Risk Preparedness Plans would contain two parts – a part reflecting national measures and a part reflecting measures to be pre-agreed in a regional context (including regional 'stress tests', procedures for cooperation in different crisis scenarios and agreement on how to deal with simultaneous electricity crisis situations).

Option 3 (Full harmonisation) entails full harmonisation and decision-making at regional level. The risk preparedness plans would be developed on regional level in order to allow a harmonised response to potential crisis situation in each region. On cybersecurity, Option 3 would go one step further and nominate a dedicated body (agency) to deal with cybersecurity in the energy sector. Crisis would have to be managed according to the regional plans agreed among Member States. A detailed 'emergency rulebook' for crisis handling would be put in place, containing an exhaustive list of measures that can be taken by Member States in crisis situations.

Regarding Problem Area IV: retail markets and the slow deployment and low levels of services and poor market performance, four policy options have been considered ranging from baseline scenario (Option 0) to full harmonization and extensive safeguards for consumers.

Option 0+ (Improved implementation/enforcement and non-regulatory approach) consists in sharing of good practices and increasing the efforts to correctly implement the legislation. This non-regulatory approach addresses competition and consumer engagement issues by strengthening the enforcement of the existing legislation as well as through bilateral consultation with Member States to progressively phase-out price regulation, starting with prices below costs. It also considers developing a Recommendation on energy bills. However, this option does not tackle the third problem driver of the market failures that prevent effective data flow between market actors.

Under Option 1 (Flexible legislation), all problem drivers are addressed through new legislation. To improve competition, Member States progressively phase-out blanket price regulation by a deadline specified in new EU legislation, starting with prices below costs, while allowing transitional price regulation for vulnerable consumers. To increase consumer engagement, the use of contract termination fees is restricted. Consumer confidence in comparison websites is fostered through national authorities implementing a certification tool. In addition, high-level principles ensure that energy bills are clear and easy to understand, through minimum content requirements. A generic adaptable, definition of energy poverty based on household income and energy expenditure is proposed in the legislation for the first time. Finally, to allow the development of new services by new entrants and energy service companies, non-discriminatory access to consumer data is ensured.

Building on Option 1, Option 2 (Full harmonisation and extensive consumer safeguards) aims to provide maximum safeguards for consumers and extensive harmonisation of Member States action throughout the EU. Exemptions to price regulation are defined at EU level on the basis of either a consumption threshold or a price threshold. A standard data handling model is enforced and assigns the responsibility to a neutral market actor such as a TSO. All switching fees including contract termination fees are banned and the content of energy bills is partially harmonized. Finally, an EU framework to monitor energy poverty based on an energy efficiency survey done by Member States of the housing stock as well as preventive measures to avoid disconnections are put in place.

VI POLICY TRADE-OFFS

The measures considered in this impact assessment are highly complementary. Most of the different options considered in each problem area would reinforce the effect of options in other problem areas, with little trade-offs between the different areas. The overall beneficial effects will be achieved only if all measures are implemented as a package

The measures under Problem Area I and II are strongly linked in that they collectively aim at improving market functioning, including the delivery of investment by the market.

Measures under Problem Area I and Option 1 of Problem area II thus reduce the need for market government intervention by means of capacity mechanisms. The other measures under Problem Area II reduce their distortive effects if such mechanisms are nonetheless justified.

Scarcity pricing and capacity mechanisms can to a certain degree be seen as alternative measures to foster investments. With assets remunerated by capacity mechanisms, the effectiveness of scarcity prices may be reduced. It needs also to be noted that scarcity prices and market-wide capacity mechanisms incentivise different investment decisions: whereas such capacity mechanisms may reward any firm capacity, scarcity pricing will improve remuneration of flexible capacity in particular.

The measures aiming at providing adequate price signals (measures under Problem Area I and Problem Area Option 1) are no-regret options. Until these conditions are achieved and under specific circumstances (like energy isolation), State intervention in the form of some type of capacity mechanism may be necessary. That is why it is essential that such mechanisms are properly designed, taking into account the wider regional and European resources and allowing cross-border participation in a technology-neutral manner.

The measures assessed under various options in the impact assessment seek to improve the overall flexibility of the electricity system. However, they do this by employing different means. Investment in new interconnection capacity may reduce the need for new generation and vice-versa, new generation can reduce the incentives for new interconnector capacity. Similarly, pulling demand response into the market will reduce the profits of generation capacity. Ultimately, the efficient markets should opt for the most cost-efficient solutions.

Energy poverty safeguards whose costs directly accrue to suppliers – particularly, the disconnection safeguards considered in Option 2 (Harmonization and extensive consumer safeguards) of Problem Area IV (Retail markets) – may act as a barrier to retail-level competition, and diminish the associated benefits to consumers, including lower prices, new and innovative products, and higher levels of service. Although the implementation costs of these safeguards will be passed on to consumers, and therefore socialized, different energy suppliers may have different abilities to do this, and to deal with the additional consumer engagement costs. Some may therefore choose not to enter markets with such safeguards in place.

VII. ANALYSIS OF IMPACTS AND CONCLUSIONS

All options have been compared against each other using, the baseline scenario as a reference and applying the following criteria:

- Effectiveness: the options proposed should first and foremost be effective and thus be suitable to addressing the specified problem;
- Efficiency: this criterion assesses the extent to which objectives can be achieved at the least cost (benefits versus the costs).

Policy options regarding the need to adapt the market design to the increasing share of variable decentralised generation and technological developments (Problem Area I)

Options 1(a) (level playing field), 1(b) (strengthening short-term markets) and 1(c) (demand response/distributed resources) represent an interlinked set of measures regarding the integration of the national electricity markets and present a compromise between bottom-up initiatives and top-down steering of the market development, without substituting the role of national governments, regulators and TSOs by a centralised and fully harmonised system.

However, Option 1(a) (level playing field) and Option 1(b) (strengthening short-term markets) do not cover measures to pull all distributed flexible resources (demand-response, renewable electricity and storage) into the market. These options do not take advantage of the potential offered by these resources to efficiently operate and decarbonise the electricity market.

In this context, Option 1(c) (demand response/distributed resources) provides a more holistic, effective and efficient package of solutions. While this option may lead to minor additional administrative impacts for Member States and competent authorities regarding the implementation and monitoring of the measures, these impacts will be offset by lower barriers to entry to start-ups and SMEs, by the benefits to market parties from more stable regulatory frameworks and new business opportunities as well as by the benefits to consumers from more competition and access to wider choice.

As regards Option 2 (fully integrated market), while having advantages in terms of less coordination requirements (i.e., a fully integrated EU-market can be operated more efficiently), the results of the assessment indicate that the move towards a more integrated European approach has less significant economic added value since most of the benefits will have already been reaped under the regional, more decentralised approach under option. In addition, it has significant impacts on stakeholders, Member States and competent authorities since it requires significant changes to established practices.

Preferred option for Problem Area I: Option 1(c) (demand response/distributed resources, also encompassing options 1(a) (level playing field) and 1(b) (strengthening short-term markets))

Policy options regarding uncertainty about sufficient future generation investments and uncoordinated capacity mechanisms (Problem Area II)

Option 1 (reinforced energy only market without capacity mechanisms) can in principle provide the right signals for market operation and ensure system adequacy and ensure better utilisation of resources across borders, demand participation and renewable integration without subsidies. Improving the functioning of electricity markets will improve the conditions for investment in the electricity market to ensure reliable and effective supply of electricity, even in times of scarcity. This will in turn decrease the need for capacity mechanisms.

However, markets are today still characterised by manifold regulatory distortions today and removing the distortive effects will not be possible with immediate effects in many Member States. Besides under such option, uncertainty about future policy directions or governmental interventions still exists. Such uncertainty may hamper investment and in turn create the need for mechanisms that address the lack of investments ('missing money').

It should be noted that undistorted energy price signals are fundamental irrespective of whether generators are solely relying on energy market incomes or also receive capacity payments. Therefore the measures aimed at removing distortions from energy-only markets discussed under Option 1(a) to 1(c) (e.g. scarcity pricing or reinforced locational signals) are 'no-regrets' and assumed as being integral parts of Options 2, 3 and 4.

Option 2 **(**Improved energy markets – Capacity Mechanisms ('CM's) only when needed, based on a common EU-wide adequacy assessment can improve the overall cost-efficiency of the electricity sector through establishing an EU-wide approach to system adequacy assessments as opposed to national-based adequacy assessments. At the same time Option 2 does not allow reaping the full benefits of cross-border participation in capacity mechanisms.

A more coordinate approach to state interventions across Member States is needed and is a clear priority for reform. Placing capacity mechanisms into a more regional/EU context is a pre-requisite to reduce market distortions. It is indeed necessary that the schemes Member States introduce are compatible with internal market rules.

Option 3 (Improved energy market – CMs only when needed, plus cross-border participation) proposes additional measures to avoid fragmentation of capacity mechanisms and ensures that foreign resource providers can effectively participate in national capacity mechanisms and avoids competition and market distortions resulting from capacity payments which are reserved to domestic participants. As a result, it reduces investment distortions that might be present in Option 2 because of uncoordinated approaches to cross-border participation.

Preferred option for Problem Area II: Option 3 (Improved energy market – CMs only when needed, plus cross-border participation) (encompassing also Options 1 and 2)

Policy options regarding the lack of coordination among Member States when preparing for and managing electricity crisis situations (Problem Area III)

Based on a set of clear common rules, Option 1 (Common minimum EU rules) would improve the level of transparency and crisis management across Europe and is likely to reduce the chances of premature market intervention. The policy tools proposed under this option would bring economic benefits to businesses and consumers by helping to prevent costly blackout situations. However, this option does not solve the issue of uncoordinated planning and preparation ahead of a crisis since Member State are not required to take into account cross-border risks and crisis.

Under Option 2 (EU rules + regional cooperation), the regionally coordinated plans ensure the regional identification of risks and the consistency of the measures for prevention and managing crisis situations while respecting national differences and competences. This significantly improves the level of preparedness (compared to Option 1) at national, regional and EU level, as the cross border considerations are duly taken into account since the beginning. A regional approach to security of supply results in a better utilisation of power plants and guarantees risk preparedness at a lesser cost.

Under Option 3 (Full harmonisation), the estimated impact on cost is likely to be high (notably with the creation of an EU agency on cyber-security) and the measures put forward appear disproportionate compared to the expected effectiveness. Indeed, this option represents a highly intrusive approach – with significant administrative impact - by resorting to a full harmonisation of principles and the prescription of concrete solutions.

Preferred option for Problem Area III: Option 2 (EU rules + regional cooperation)

Policy options regarding retail markets and the slow deployment and low levels of services and poor market performance (Problem Area IV)

Given its low implementation costs, Option 0+ (Non-regulatory approach) is a highly efficient option. However, the effectiveness of Option 0+ is significantly limited by the fact that non-regulatory measures are not suitable for tackling the poor data flow between retail market actors that constitutes both a barrier to entry and a barrier to higher levels of service to consumers. In addition, shortcomings in the existing legislation make it impossible to significantly improve consumer engagement and energy poverty safeguards. They also introduce great uncertainty around the drive to phase out price regulation which does not provide sufficient incentives to consumers to play an active role in the market and which also limits competition and new entrants into the market.

Option 1 (Flexible legislation) would lead to substantial economic benefits. Retail competition would be improved as a result of the progressive phase-out of blanket price regulation, non-discriminatory access to consumer data, and increased consumer engagement. In addition, consumers would see direct benefits through improved switching.

In Option 2 (Harmonization and extensive consumer safeguards) there is uncertainty over the size of the economic benefits. This uncertainty stems from the tension some of the measures in Option 2 may have with competition (stronger disconnection safeguards, an outright ban on all switching-related charges), and from the difficulty of prescribing EU-level solutions in certain areas (defining exceptions to price deregulation, implementing a standard EU bill design). Besides, a single EU data management model would have high implementation costs, thus reducing the efficiency of the option.

Preferred option for Problem Area IV: Option 1 (Flexible legislation)

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1. INTRODUCTION

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1.1.1. Context of the initiative

1.1.1.1.The gradual process of creating an internal electricity market

Well-functioning energy markets that ensure secure energy supplies at competitive prices are key for achieving growth and consumer welfare in the European Union.

Since 1996, the European Union has put in place legislation to enable the transition from an electricity system traditionally dominated by vertically integrated national incumbents that owned and operated all the generation and network assets in their territories to competitive, well-functioning and integrated electricity markets. The first step was the adoption of the First Energy Package (1996 for the electricity sector and 1998 for the gas sector), which allowed for the partial opening of the market where the largest consumers were given the right to choose their supplier. The Second Energy Package (2003) introduced changes concerning the structure of the vertically integrated companies (legal unbundling), the preparation of the full opening of the market by 1 July 2007 and the reinforcement of the powers of the national regulators. The most recent comprehensive reform of European energy market rules, the Third Internal Energy Market Package (2009)[1] ('Third Package') has principally aimed at improving the functioning of the internal energy market and resolving structural problems.

Since the adoption of the Third Package, electricity policy decisions have enabled competition and increasing cross-border flows of electricity, notably with the introduction of so called "market coupling"[2] and "flow-based" capacity allocation. In spite of significant differences in the maturity of markets in Europe, overall electricity wholesale markets are increasingly characterised by fair and open competition, and – though still insufficient – competition is also taking root at the retail level.

1.1.1.2.The Union's policy concerning climate change

The decarbonisation of EU economies is at the core of the EU’s agenda for climate change and energy. The targets in the Climate and Energy Package (2007) require Member States to cut their greenhouse gas emissions by 20% (from 1990 levels), to produce 20% of their energy from renewable energy sources (RES), and to improve energy efficiency by 20 % (**the '2020 targets**').[3]

In 2011, the European Union committed to reduce greenhouse gas emissions to 80-95% below 1990 levels by 2050. For this purpose, the European Commission adopted an

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1 Section 1.1.2.1 provides a more detailed explanation of the Third Energy Package.

2 A mechanism that manages cross-border electricity flows in an optimal way, smoothing out price differences between Member States.

3 http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52008DC0030&from=EN

Energy Roadmap[4] and a roadmap for moving to a competitive low carbon economy[5] exploring the transition of the energy system in ways that would be compatible with this greenhouse gas reductions target while also increasing competitiveness and security of supply. The 2050 roadmap will require a higher degree of decarbonisation from the electricity sector compared to other economic sectors.

These ambitions were reaffirmed by the European Council of October 2014, which endorsed targets for 2030 of at least 40 % for domestic greenhouse gas emissions reduction (compared to 1990 levels), at least 27 % for the share of renewable energy consumption, binding at EU level and at least 27 % energy savings, to be reviewed by 2020, having in mind an EU level of 30% (**the '2030 targets'**).[6]

At the Paris climate conference (COP21) in December 2015, 195 countries adopted the first-ever legally binding global climate deal. The European Council of March 2016 confirmed the EU's commitment to implement the 2030 targets. The Paris Agreement was ratified by the European Union and entered into force on 4 November 2016..

1.1.1.3.Paradigm shift in the electricity sector

The Union's goals for climate change and energy have led to a paradigm shift in the means employed to generate electricity: since the adoption of the Third Package, there has been a move towards the deployment of capital-intensive low marginal cost, variable and often decentralised electricity from RES E (mostly from solar and wind technologies) that is expected to become more pronounced by 2030.

The increasing penetration of RES E is driven *inter alia* by the objective to reduce greenhouse gas emissions in line with the 2020 and 2030 targets. The 2030 greenhouse gas emission reduction target is to be delivered through reducing emissions by 43% compared to 2005 for the sectors in the EU's ETS[7] (including the electricity sector and industry) and by 30% compared to 2005 for the sectors outside the ETS. Within the electricity sector, the reduction of greenhouse gas emissions is supported by the Renewable Energy Directive[8], the ETS and the additional national policies by Member States to increase the share of renewables in the energy mix.

The Renewable Energy Directive established a European framework for the promotion of renewable energy, setting mandatory national renewable energy targets for achieving a 20% EU share of renewable energy in the final energy consumption and a 10% share of energy from renewable sources in transport by 2020. These objectives have translated

4 http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52011DC0885&from=EN

5 COM (2011) 112; http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52011DC0112

6 http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/145397.pdf

7 The ETS works on the *'cap and trade'* principle. A *'cap'*, or limit, is set on the total amount of certain greenhouse gases that can be emitted by the factories, power plants and industrial installations in the system. The cap is reduced over time so that total emissions fall. This policy instrument equally fosters penetration of RES E as it renders production of electricity from non- or less-emitting generation capacity comparatively more economical in relation to more carbon intensive capacity.

8 Directive 2009/28/EC on the promotion of the use of energy from renewable sources, OJ L 140/16, 5.6.2009

into a need to foster the increased production of electricity from reneweble energy sources.[9]

In parallel with the increased deployment of variable and decentralized RES E, the increasing digitalisation of electricity networks and the environment behind the meter now enables many elements of the electricity system to be operated more flexibly and efficiently in the context of RES E generation. It also allows smaller actors to play an increasingly important part in the market on both the supply side and – crucially – the demand side, potentially untapping a vast new system resource.

From the consumer's perspective, increasingly intelligent grids unlock a host of other possibilities, including innovative new products and services, lower entry barriers for new suppliers, and improved billing and switching. This promises to unlock value and improve the consumer experience – provided the legislative framework adapts to the changing needs and possibilities. Indeed, fully engaging end consumers will be essential to realizing the full benefits that the digital transformation can bring in terms of grid flexibility.

Moreover, electricity demand will progressively reflect the increasing electrification of transport and heating.

The challenges the EU's electricity systems face are reflected in the European Commission Communication of February 2015 on *“A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy”*[10] where the Commission announced a new electricity market design linking wholesale and retail markets. As part of the legislative reform process needed to establish the Energy Union, it also announced new legislation on security of electricity supply.

In the light of the Energy Union Framework Strategy, the present impact assessment reflects and analyses the need and policy options for a possible revision of the main framework governing electricity markets and security of electricity supply policies in Europe. The new electricity market design contributes strongly to the overall Energy Union objectives of securing low carbon energy supplies to the European consumers at least costs.

1.1.1.4.The vision for the EU electricity market in 2030 and beyond

The Energy Union Framework Strategy sets out the vision of an Energy Union "*with citizens at its core, where citizens take ownership of the energy transition, benefit from new technologies to reduce their bills, participate actively in the market, and where vulnerable consumers are protected*". Well-functioning energy markets that ensure secure energy supplies at competitive prices are important for achieving growth and

[9] Moreover, following the 2030 targets set by the European Council in October 2014, the Commission published a Communication on A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy of February 2015 confirming the political commitment for the European Union to become the world leader in renewable energy.

[10] EC (2015a) - COM(2015) 80 final

consumer welfare in the European Union. The future of the entire energy sector will, to a significant extent, be shaped by the evolution of the electricity sector, which is key to addressing climate change. With the quick ratification of the global Paris Agreement on climate change and its subsequent entry into force, it becomes clear how important it is for all parties to the agreement, including the EU, to deliver on the clean energy transition on the ground. In fact, amongst all sectors that make up our energy system, electricity is the most cost-effective to decarbonise. Currently 27.5% of Europe's electricity is produced from renewable energy sources. The share of RES E in electricity generation needs to almost double by 2030 in order for the EU to meet its 2030 energy and climate targets cost-effectively. This will require creating the right conditions for the massive amount of investment needed for this energy transition to come about. At the same time electricity markets will have to adapt to the radical change in the structure of the generation pattern which will foremost require creating a more flexible market, going across borders, that is able to allow more active participation of a much wider range of actors.

The EU's vision of the electricity system in 2030 is therefore based on a functioning market that is adapted to implementing the decarbonisation agenda at least cost together with a revised EU ETS. A well-functioning electricity market is also the most efficient tool to ensure secure electricity supplies at the lowest reasonable cost.

The transition of the energy system towards the 2030 vision

The starting point is the existing reality, which dates back to an era with large-scale, centralised power plants, largely fuelled by fossil fuels, had the key aim of supplying every home and business in a delineated area – typically a Member State – with as much electricity as they wanted, and in which consumers – households, businesses and industry – were passive users.

However, the electricity market is undergoing profound change and requires a new set of rules to ensure secure supplies, competitiveness while enabling cost-effective decarbonisation. The electricity market of the next decade will be characterised by more variable and decentralised electricity production, an increased interdependence between Member States and new technological opportunities for customers to reduce their bills and actively participate in electricity markets through demand response, self-consumption or storage.

The electricity market design initiative aims to improve the functioning of the internal electricity market in order to allow electricity to move freely to where and when it is most needed, empower consumers, reap maximum benefits for society from cross-border competition and provide the right signals and incentives to drive the right investments compatible with climate change, renewable energy and energy efficiency ambitions.

The proposed initiative constitutes a next-step in a wider and longer evolutionary process that will guide the EU's electricity markets towards the 2030 vision.

The 2030 electricity market is highly flexible and provides a level playing field amongst all forms of generation as well as demand response…

The bulk of the new generation capacity is likely to come from renewable sources, mainly wind and sun that are variable and predictable only to a limited extent. The future electricity market will therefore need to be more flexible and liquid than today and allow for integrated short-term trading. This would also set the ground for renewable energy producers – who will over time acquire increasing share in generation - to equally access energy wholesale markets and to compete on an equal footing with conventional energy producers. Short-term markets will also allow Member States to share their resources across all "time frames" (forward trading, day-ahead, intraday and balancing), taking advantage of the fact that peaks and weather conditions across Europe do not occur at the same time. This would provide maximum opportunity to meet the flexibility needs and balance the market. The sequence of forward markets and spot markets - day-ahead, intraday and balancing - will optimise prices and the system in the short-run and will reveal the true value of electricity and, therefore, provide appropriate investments signals in the long-run.

The closer to real time electricity is traded (supply and demand matched), the less the need for costly interventions by TSOs to maintain a stable electricity system. Although TSOs would have less time to react to schedule deviations and unexpected events and forecast errors, the liquid, better interconnected balancing markets, together with the regional procurement of balancing reserves and more balancing actors and products available from both demand and supply side, would be expected to provide them adequate and more efficient resources in order to manage the grid and facilitate RES E integration.

All this will help to create a level playing field not only among all modes of generation but also the demand side. At the same time market distortions and rules that artificially limit or favour the access of certain technologies to the grid would be removed. All market participants would become gradually responsible for balancing their position in the market, bearing financial responsibility for the imbalances they cause and would, therefore, be incentivised to reduce the risk of such imbalances. The most cost-efficient sources of electricity would be used first, curtailment of generation due to limited transmission and distribution infrastructure would be a measure of last resort and confined to situations in which no market-based responses (including storage and demand response) are available, and subject to transparent rules known in advance to all market actors and adequate financial compensation. All resources would be remunerated in the market on equal terms.

…and active consumers.

Ensuring that all consumers – big and small – can actively participate in the energy market would unlock a vast system resource that could play an important role in reducing system costs. Technology – including smart grids and smart homes - is already available and will further develop to enable consumers to modulate their demand while maintaining comfort and reducing costs.

In the future, consumers would be sufficiently incentivised to benefit from these opportunities and thus demand response would be provided by all willing consumer groups, including residential and commercial consumers either directly or through intermediaries (like aggregators). This would further increase the flexibility of the electricity system and the resources for the TSOs and DSOs to manage it. At the same time it should lead to a much more efficient operation of the whole energy system.

Consumers would be able to react to price signals on electricity markets both in terms of consumption and production; they would consume when prices are low, when there is plenty of electricity available, and reduce their consumption at times of low electricity production and high prices. To make this possible, consumers have access to a fit-for-purpose smart metering system, smart homes and storage as well as electricity supply contracts with prices linked dynamically to the wholesale markets.

More and more consumers would produce their own electricity. Such decentralised production further strengthens security of supply and helps to implement the decarbonisation agenda as most of this production comes from renewable sources. If combined with local storage solutions, consumers could significantly contribute to balancing the distribution grids at local level. Analysis suggests that this development will be progressive, and that most consumers would still remain connected to the distribution grid to use it as back-up for when the prosumers' own generation is inadequate (e.g. for sustained periods of low sunlight) or for the opportunity to sell excess electricity to the market (e.g. during prolonged sunny periods when their installed storage is at full capacity).

Reducing barriers to market entry for electricity suppliers and consumer engagement – notably phasing out price regulation – results in increased competition at the retail level allowing consumers to save money through better information and a wider choice of action. This also helps drive the uptake of innovative new products and services that increase system flexibility through demand response whilst catering to consumers' changing needs and abilities.

In addition, DSOs would be enabled and incentivised, without compromising their neutrality as system operators, to manage their networks in a flexible and cost-efficient way – inter alia through revised tariff structures.

Increased cross-border trade is a pillar of the electricity market.

Competition and cross-border flows of electricity would further increase, with fully coupled markets where price differences between Member States are smoothened out. Electricity wholesale markets will be characterised by fair and open competition, including across borders. Cooperation between TSOs will be enhanced by regional operational centres. The cross-border cooperation of TSOs would be accompanied by an increased level of cooperation between regulators and governments. An adequate cross-border infrastructure remains crucial to underpin a well-functioning electricity market.

Increasingly investments are triggered by the market with a decreasing need for state subsidies.

The enhanced market design, the revised renewables directive and the strengthened ETS will all help to improve the viability of RES E investments, in particular as follows:

- Where the marginal producer is a fossil fired power plant, a higher carbon price translates into higher average wholesale prices. The existing surplus of allowances is expected to decrease due to the implementation of the Market Stability Reserve and the higher Linear Reduction Factor, reducing the current imbalance between supply and demand for allowances;

- greater system flexibility will be critical for better integration of RES E in the system, reducing their hours of curtailment and the related forgone revenues; improving overall system flexibility is equally essential to limit the merit-order effect[11] and thus in avoiding the erosion of the market value of RES E produced electricity;
- the revision of priority dispatch rules, removal of must-run units, increasing demand response and storage, together with the better functioning of the short-term markets will strongly reduce or even eliminate the occurrence of negative prices – leading again to higher average wholesale prices (especially during the hours with significant variable RES E generation);
- improved rules for intraday and balancing markets will increase their liquidity and allow access to those markets for all resources, thus helping generators reduce their balancing costs;
- removing existing (explicit or implicit) restrictions for the participation of all resources to the reserve and ancillary services markets will allow RES E to generate additional revenues from these markets;
- price signals reflecting the actual value of electricity at each point of time, as well as the value of flexibility, will ensure that the flexible assets most needed for the system are invested in or, at least, are less likely to be decommissioned.
- Low exit barriers to facilitate exit of overcapacities.

The above mentioned changes will all help to improve the competitive situation of RES E and reduce the need for dedicated support.

The results of the modelling for this Impact Assessment indicate that investments in the most mature renewable technologies could be driven by the market by 2030 (such as certain solar PV and onshore wind). At the beginning of the period, generation over-capacity in certain areas, weaker investment signal from the ETS and low wholesale market prices and still high RES E technology costs, make the case for investments in RES E technologies more difficult. The underpinning modelling and analysis, points that the RES E funding gap in 2020 is gradually reducing towards 2030 as the market conditions improve. Less mature RES E technologies, needed for meeting the 2030 and 2050 energy and climate objectives, such as off-shore wind, will likely need some form of support to cover at least a fraction of total project costs (complementing the revenues obtained from the energy markets) throughout the 2021-2030 period.

The picture also depends on regions. RES E technologies could be more easily financed by the market in the regions with the highest potential (*e.g.* onshore wind in the Nordic region or solar in Southern Europe), while RES E could continue to require support in the British Isles and in Central Europe. Conditions however also depend on the cost of capital.

At the same time it has to be acknowledged that whether and what point in time financing of RES E through markets alone will actually take off remains difficult to predict. This is because financing of capital intensive technologies such as most RES E

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[11] Also occasionally referred to as the 'cannibalisation effect'.

through markets based on marginal cost pricing will remain challenging. In the absence of measures that address system flexibility, higher penetration of RES with low marginal cost could reduce the market value that such RES E can actually achieve. Removing barriers to the flexibilisation of demand and improving the responsiveness of demand and supply to price signals stands out as a key measure in this regards in order to further stabilise the revenue of RES E producers from the market.

On the other hand the future capacity of RES to be financed through the market will also depend on certain conditions outside of the market design and ETS prices, such as continued decrease in the costs of technologies, availability of capital at a reasonable price, social acceptance and sufficiently high and stable fossil fuel prices.

While the market reforms described above are therefore no regret options to facilitate RES investment, support schemes will still be needed at least for a transitional period. It is therefore essential to further reform such schemes to make them as market-oriented as possible.

… with a market-based and more Europeanised approach to support schemes to cover any investment gap .

Where needed, support will be (i) cost-effective and kept to a minimum, and (ii) will create as little distortions as possible to the functioning of electricity markets, and to competition between technologies and between Member States. The legal frame for RES E support schemes would ensure sufficient investor certainty over the 2021-2030 period and require the use (where needed) of market-based and cost-effective schemes, based on the design of emerging best practices. Auctions could introduce competitive forces to determine the level of support needed on top of market revenues and incentivise RES E producers to develop business models that maximise market-based revenues. The use of tenders would imply a natural phase-out mechanism for support, determining the remaining level of support required to bridge any financing gap. The continued participation of small and local actors, including energy communities, in the energy transition should be ensured in this process.

The market should also provide, as a principle, security of supply.

By 2030, the market, as described above, could in principle successfully attract the required investments to ensure adequate matching of supply and demand.

Today, most of the EU's power markets have more capacity than needed. However, with demand increasing, e.g. due to E-Mobility and heat pumps, and older power plants retiring supply margins are likely to get tighter. Therefore, a legal framework needs to be in place to allow for the formation of electricity prices that send the signals for tomorrow's investments. In this context, scarcity prices will become more and more important to provide the right incentives for the operation of resources (including for demand response) when they are most needed. Hedging products which suppliers can buy to protect themselves against peaks are already available now and more innovative tools are expected to be brought forward by market participants without the need for additional intervention by national authorities. This will also provide opportunities for generators (who will be natural provider of such hedging tools) to secure further revenues.

In the new market framework capacity mechanisms might only be considered if a residual risk to security of supply can be proven after underlying market distortions have been removed and the contribution of market integration to security of supply has been taken into account.

The legal framework will provide tools to facilitate an objective case-by-case judgement on whether the introduction of capacity mechanisms is needed and set out measures to ensure that their potentially distortive effects are kept at a minimum, while placing them in a more regional context. Accordingly, their need would have to be proven against an EU-wide system adequacy assessment and they would have to allow for cross-border participation to minimise distortions of investment incentives across the borders. Capacity mechanisms would be designed in a way as to not discriminate against different generation technologies and demand side capacities. Additionally, where need has been demonstrated for such mechanisms, Member States should take into account how such mechanisms would impact the achievement of the decarbonisation objectives.

Member States should regularly review their resource adequacy[12] situation and phase out capacity mechanisms once the underlying market or regulatory concerns have been resolved.

Despite best efforts to build an integrated and resilient power market, crisis situations can never be excluded. The potential for crisis situation increases with climate change (i.e. extreme weather conditions) and with the emergence of new areas that are subject to criticalities (i.e. malicious attacks, cyber-threats). Such crises tend to often have an immediate cross-border effect in electricity. The legal framework would provide tools to ensure that national security of supply policies are better coordinated and aligned to tackle possible crisis situations, in particular those that affect several countries at the same time.

1.1.2. Scope of the initiative

1.1.2.1.Current relevant legislative framework

EU's electricity markets are currently regulated at EU level by a series of acts collectively referred to as the "Third Package"[13].

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[12] As not only generation, but also demand response or storage can solve problems of situations in which demand exceeds production, this Impact Assessment uses the term "resource adequacy" instead of "generation adequacy" (other authors refer to "system adequacy").

[13] The relevant elements of the Third Package as regards electricity are Directive 2009/72 of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, OJ L 211, 14.8.2009, p. 55–93; Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity repealing Regulation (EC) No 1228/2003. OJ L 211, 14.8.2009, p. 15–35 and Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators. OJ L 211, 14.8.2009, p. 1–14. The Third package also covered other acts, in particular acts related to the regulation of gas markets. However, only one of these acts is pertinent for the present impact assessment – the Gas Directive.

The main objectives of the Third Package were:

- Improving competition through better regulation, unbundling and reducing asymmetric information;
- Improving security of supply by strengthening the incentives for sufficient investment in transmission and distribution capacities; and,
- Improving consumer protection and preventing energy poverty.

The Third Package mainly focused on improving the conditions for competition as resulting from previous generations of legislation by improving the level playing field. The most important root cause for the lack of competition identified at the time[14] was the existence of vertically integrated companies, which not only controlled essential facilities (such as electricity transmission systems) but also enjoyed significant market power in the wholesale and, often, retail markets. Many of the measures associated with the Third Package sought to directly or indirectly address this issue, such as by improving the unbundling regime, strengthening regulatory oversight, improving the conditions for cross-border market integration and lowering entry barriers such as by improving transparency.

The Third Package also created the possibility to enact secondary legislation concerning cross-border issues, often referred to as network codes or guidelines ('network codes')[15], and provided a mandate for developing these network codes (as well as other tasks related to the EU's electricity markets) to transmission system operators within the **ENTSO-E**[16] and to national regulatory authorities, within the Agency for the Cooperation of Energy Regulators ('**ACER**')[17].

The main framework for electricity security of supply in the Union is currently Directive 2005/89/EC ("**Security of Electricity Supply Directive'** or **'SoS Directive**'")[18]. This SoS Directive requires Member States to take certain measures with the view to ensuring security of supply, but leaves it by and large to the Member States how to implement these measures. The Third Package complemented the SoS Directive and superseded *de facto* some of its provisions.

1.1.2.2.Policy development subsequent to the Third Package

The present initiative builds on previous related policy initiatives and reports that intervened since the adoption of the Third Package and the Security of Electricity Supply Directive, in particular:

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[14] In the impact assessment for the Third Package (SEC(2007) 1179/2 http://ec.europa.eu/smart-regulation/impact/ia_carried_out/docs/ia_2007/sec_2007_1179_en.pdf.

[15] For an overview of these network codes and guidelines and their pertinence to the present initiative, please refer to Annex VII.

[16] https://www.entsoe.eu/about-entso-e/inside-entso-e/official-mandates/Pages/default.aspx

[17] http://www.acer.europa.eu/en/The_agency/Mission_and_Objectives/Pages/default.aspx

[18] Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment, OJ L 33, 4.2.2006, p. 22–27.

- *"Report on the progress concerning measures to safeguard security of electricity supply and infrastructure investment"* COM (2010) 330 final[19];
- *"Delivering the internal electricity market and making the most of public interventions"* (C(2013) 7243). This Communication was accompanied *inter alia* by a Commission Staff working document (SWD(2013)438) entitled *"Generation Adequacy in the internal electricity market – guidance on public intervention"*;
- Communication on the "*Progress towards completing the Internal Energy Market*" COM(2014) 634 final. This Communication emphasized that energy market integration has delivered many positive results but that, at the same time, further steps are needed to complete the internal market;
- *"Communication on Energy Security"* (COM(2014)330). This Communication emphasised *inter alia* the need achieve a better functioning and a more integrated energy market;
- Special Report by the European Court of Auditors *"Improving the security of energy supply by developing the internal energy market: more efforts needed"*. This special report made nine recommendations to reap the benefits of market integration[20];
- *"Communication on energy prices and costs in Europe"* (COM(2014) 21 /2) and the accompanying "*Energy prices and costs report*" (SWD(2014)020 final 2) highlighting *inter alia* the competiveness of the EU's retail electricity markets, the missing link between wholesale and retail prices and the need for EU cooperation by DSOs as well as the Energy prices and costs report (SWD(2016)XX[21], this report *inter alia* that shed light on the drivers of retail and wholesale price developments;
- *"Delivering a new deal for energy consumers"* (COM(2015) 339). This Communication laid out the Commission's intention to enable all consumers to fully participate in the energy transition, taking advantage of new technologies that enable wholesale and retail markets to be better linked.
- The Commisison published a study on *"Investment perspectives in electricity markets"*[22]
- Technical Report[23] by the European Commission on "*The economic impact of enforcement of competition policies on the functioning of EU energy markets*". The report includes an assessment of the intensity of competition in the energy markets[24] (both wholesale and retail) and points out that, between 2005 and 2012, the intensity of competition in European energy markets may have declined[25].
- The Commission Staff working document (SWD(2015)249) entitled *"Energy Consumer Trends 2010 - 2015"* presents market research into the problems that energy consumers continue to be confronted with.

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19 http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52010DC0330&from=EN

20 http://www.eca.europa.eu/en/Pages/DocItem.aspx?did=34751

21 Report to be published in conjunction with the present impact assessment..

22 *"Energy Economic Developments, Investment perspectives in electricity markets"*. Institutional paper 003, 1 July 2015 http://ec.europa.eu/economy_finance/publications/eeip/pdf/ip003_en.pdf

23 Published on 16.11.2015, at http://ec.europa.eu/competition/publications/reports/kd0216007enn.pdf

24 *Ibid* Section 3.3 of the non-technical summary at p. 23.

25 Based on the productivity dispersion and the Boone indicator over this period, *ibid* Section 3.4 "*Summary of key findings*" at p. 25.

- The Commission launched a a sector inquiry into national capacity mechanisms, The resulting *"Interim Report of the Sector Inquiry on Capacity Mechanisms"* (SWD SWD(2016) 119 final)[26] points out that there is a lack of adequate assessment of the actual need for capacity mechanisms. It also appears that some capacity mechanisms in place could be better targeted and more cost effective. It emphasizes the need to design capacity mechanisms with transparent and open rules of participation and a capacity product that does not undermine the functioning of the electricity market, taking into account cross-border participation.

1.1.2.3.Scope and summary of the initiative

In line with the Union's policy on climate change and energy, the proposed initiative aims at deepening energy markets and setting a framework governing security of supply policies that enables the transition towards a low carbon electricity production.

The transition towards a low carbon electricity sector as well as technical progress will have profound implications on the manner in which the electricity sector is organised and the roles of market actors and consumers, not all of which can be foreseen with accuracy today. As it cannot be predicted how the electricity markets and progress of innovation will look like in a few decades from now, the proposed initiative constitutes a next step in a wider and longer evolutionary process that will guide the EU's electricity markets towards the future. The initiative will consequently not address the challenges that might arise when operating a fully decarbonised power system.[27]

This initiative also aims at improving consumer protection and engagement for both electricity and gas consumers[28].

1.1.3. Organisation and timing

1.1.3.1.Follow up on the Third Package

Full and timely transposition of the Directives of the Third Package has been a challenge for the vast majority of the Member States. In fact, by the end of the transposition deadline (March 2011), none of the Member States had achieved full transposition. However, progess has been made and at present all of the infringement proceedings[29] for partial transposition of the Electricity Directive have been closed as the Member States achieved full transposition in the course of the proceedings.

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[26] Published on 13.04.2016 at: : http://ec.europa.eu/competition/sectors/energy/capacity_mechanism_report_en.pdf

[27] For some of the arising issues and challenges see Chapter 2.3 in Investment Perspectives in Electricity Markets, European Commission, DG EFCIN, 2015 http://ec.europa.eu/economy_finance/publications/eeip/pdf/ip003_en.pdf

[28] With regards to gas consumers, only the consumer-related provisions of the Gas Directive are concerned: Article 3 and Annex I. These address issues such as public service obligations, metering, billing and a broad range of consumer rights that Member States shall ensure.

[29] The Commission opened 38 infringement cases against 19 Member States for not transposing or for transposing only partially the Directives.

In addition to ensuring compliance of national rules with the Third Package, the Commission has carried out assessments to identify and resolve problems concerning incorrect transposition or bad application of the Third Package. On this basis, the Commission has opened EU Pilot cases against a number of Member States. As of 7th July 2016, 8 of these EU Pilot cases have resulted in infringement procedures where, *inter alia*, the violation of the EU electricity market rules is at stake.

In January 2014 the Directorate General for Energy of the European Commission ('DG ENER') launched a public consultation on retail markets for energy.

Whilst preparing the single market progress report (COM(2014) 634 final), published on 13 October 2014, DG ENER decided to study a number of changes to the current legislation.

The Commission (DG ENER) started in 2015 the preparatory work for the present impact assessment to assess policy options related to the internal energy market for electricity and to security of electricity supply and consulted in July 2015 the public on a new energy market design (COM(2015) 340 final)[30].

In April 2015, the Commission (DG Competition) launched a sector inquiry into national capacity mechanisms. The Commission interim report and the accompanying Commission staff working document, adopted on 13 April 2016 have provided a significant input for the proposed initiative. This will be further completed by the final report.

1.1.3.2.Consultation and expertise

The Commission has conducted a number of wide public consultations on the different policy areas covered by the present Impact assessment which took place between 2014 and 2016. In addition to the public consultations, it has organised a number of targeted consultations with stakeholders throughout 2015 and 2016[31].

Given the cross-cutting nature of the planned impact assessment work, the Commission set up an inter-service steering group which included representatives from a selected number of Commission Directorate Generals. The inter-service steering group held regular meetings to discuss the policy options of the proposed initiatives and the preparation of the impact assessment[32].

In parallel, the Commission has also conducted a number of studies mainly or specifically for this impact assessment[33].

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30 https://ec.europa.eu/energy/sites/ener/files/documents/1_EN_ACT_part1_v11.pdf and https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design
31 For more information on the consultation process, please refer to Annex 3
32 For more information on inter-service steering group, please refer to Annex 1.
33 For the list of studies and a summary description, please refer to Annex 5.

1.2. Interlinkages with parallel initiatives

The proposed initiatives are strongly linked to other energy and climate related legislative proposals brought forward in parallel with the present initiative equally aimed at delivering upon the five dimensions of the Energy Union, namely energy security, solidarity and trust, a fully integrated European energy market, energy efficiency contributing to moderation of demand, decarbonisation, research, innovation and competitiveness. These other energy related legislative proposals include:

1.2.1. The Renewable Energy Package comprising the new Renewable Energy Directive and bioenergy sustainability policy for 2030 (**'RED II'**)

The RED II covers a number of measures deemed necessary to attain the EU binding objective of reaching a level of at least 27% RES in final energy consumption by 2030 across the electricity, heating and cooling, and transport sectors. As regards electricity in particular, the Renewables Directive proposes a framework for the design of support schemes for renewable electricity, a framework for renewable self-consumption and renewable energy communities, as well as various measures to reduce administrative costs and burden.

Conversely, measures aimed at the integration of RES E in the market, such as provisions on priority dispatch and access previously contained in the renewables directive are part of the present market design initiative. The reflections on a revised Renewables Energy Directive will include specific initiatives on support schemes for market-oriented, cost-effective and more regionalised support to RES up to 2030 in case Member States were opting to have them as a tool to facilitate target achievement. The Renewable Package is expected to deal with legal and administrative barriers for self-consumption, whereas the present package will address market related barriers to self-consumption.

The Renewable Energy package has synergies with the present initiative as it seeks to adapt the current market design, optimised for large-scale, centralised power plants, to a suitable one for the cost-effective operation of variable, decentralised generation of electricity whilst taking into account technological progress creating the conditions for a cost efficient achievement of the binding EU RES target in the electricity sector.

The enhanced market design will improve the viability of RES E investments, but electricity market revenues alone might not prove sufficient in attracting renewable investments in a timely manner and at the required scale to meet EU's 2030 targets. The MDI and RED II impact assessments thus jointly come to the conclusion that the improved electricity market, in conjunction with a reformed EU ETS could, under certain conditions, deliver investments in the most mature renewable technologies (such as solar PV and onshore wind). The underpinning modelling and analysis, points that the RES E funding gap in 2020 is gradually reducing towards 2030 as market conditions improve. Less mature RES E technologies, needed for meeting the 2030 and 2050 energy and climate objectives, such as off-shore wind, will likely need some form of support to cover at least a fraction of total project costs (complementing the revenues obtained from the energy markets) throughout the 2021-2030 period. These technologies are required if RES E technologies are to be deployed to the extent required for meeting the 2030 and 2050 energy and climate objectives, and provide an important basis for the long-term competitiveness of an energy system based on RES E.

Similarly, the progressive reform of RES E support schemes as proposed by the RED II initiative, building on the Guidelines on State aid for environmental protection and energy 2014-2020 ('EEAG'), is a prerequisite for the results of the present initiative to come about. In order to ensure that a market can function, it is necessary that market participants are progressively exposed to the same price signals and risks. Support schemes based on feed-in-tariffs prevent this and would need to be phased-out – with limited exemptions – and replaced by schemes that expose all resources to price signals, as for instance by means of premium based schemes. Such schemes would be made even more efficient by setting aid-levels through auctioning as RES E investments projects will then be incentivised to develop business models that optimise market based returns[34].

The issue is explored in more detail in section 6.2 of the present impact assessment and, in particular, the RED II impact assessment.

1.2.2. Commission guidance on regional cooperation

The forthcoming guidance on regional cooperation may set out general principles for regional cooperation across all five dimensions of the Energy Union, described how these principles are being addressed in this initiative and other legislative proposal for Renewables and Energy Union governance, and will offer suggestions on how regional co-operation, where it applies, can be made to work in practice.

The present initiative seeks to improve market functioning, and calls for a more regional approach to system operation and security of supply. The guidance document should help Member States best achieve regional co-operation, including in areas where the present initiative mandates effective co-operation (e.g. the initiative calls on Member States to prepare risk preparedness plans in a regional context, cf. infra).

1.2.3. The Energy Union governance initiative

The Energy Union governance initiative aims at ensuring a coordinated and coherent implementation of the Energy Union Strategy across its five dimensions with emphasis on the EU's energy and climate targets for 2030. This is established through a coherent combination of EU-level and national action, a strengthened political process and with reduced administrative burden.

With these objectives in mind, the draft Regulation is based on two pillars:

- Streamlining and integration of existing planning, reporting and monitoring obligations in the energy and climate fields, in order to reduce unnecessary administrative burden;

- A political process between Member States and the Commission with close involvement of other EU institutions to support the achievement of the Energy

[34] See Box 7 and Annex IV for more information

Union objectives, including notably the 2030 targets for greenhouse gas emission reductions, renewable energy and energy efficiency.

In relation to this initiative the governance initiative will also streamline reporting obligations by Member States and the Commission that are presently enshrined in the Third Package.

1.2.4. The Energy Efficiency legislation ('EE')[35] and the related Energy Performance of Buildings Directive ('EPBD')[36] including the proposals for their amendment.

In general terms, energy efficiency measures interact with the present initiative as they affect the level and structure of electricity demand. In addition, energy efficiency measures can alleviate energy poverty and consumer vulnerability. Besides consumer income and energy prices, energy efficiency is one of the major drivers of energy poverty.

The provisions currently still in the current energy efficiency legislation concerning metering and billing (to the extent related to electricity) may become part of the present initiative as these relate to consumer conduct and their participation in the market which are important issues in the context of the present initiative. This logic is reinforced by the fact that the Third Package already contains closely related provisions on smart metering deployment and fuel mix and comparability provisions in billing.

Similarly, all provisions on priority dispatch for Combined Heat and Power ('CHP') previously contained in the energy efficiency legislation will be set out in the present initiative as these provisions relate to the integration of these resources in the market and as they are very similar to the priority dispatch provisions for RES E, also dealt with in the present initiative.

The provisions previously contained in the energy efficiency legislation on demand response will be set out in the present initiative[37] because these relate to incentivising flexibility in the market and participation of consumers in the market, both core subjects of the present initiative. This logic is reinforced by the fact that the Third Package already contains related provisions on demand response.

1.2.5. The Commission Regulation establishing a Guideline on Electricity Balancing ('Balancing Guideline')

The Balancing Guideline constitutes an implementing act that will be adopted using the Electricity Regulation as a legal basis. The Balancing Guideline is closely related to the present initiative. This is because efficient, integrated balancing markets are an important

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35 Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC; OJ L 315, 14.11.2012, p. 1–56.

36 Directive 2010/31/EU of the European Parliament and of the Council of 19 May 2010 on the energy performance of buildings. OJ L 153, 18.6.2010, p. 13–35.

37 In a manner that will preserve DG Energy's ability to continue infringing Member States that have not correctly implemented what is now Article 15(8) of the Energy Efficiency Directive.

building block for the consistent functioning of wholesale markets which in turn are needed for a cost effective integration of RES E into the electricity market.

The Balancing Guideline aims at harmonising certain aspects of the EU's balancing markets, with a focus on optimising the cross-border usage that TSOs make of the balancing reserves that each have decided to contract individually, such as harmonisation of the pricing methodology for balancing; standardisation of balancing products and merit-order activation of balancing energy.

The present initiative seeks in contrast to focus on a more integrated approach to deciding and contracting of the balancing reserves, as opposed to their usage, which touches upon the optimal allocation of the cross-border transmission capacities and a regional approach to balancing reserves.

Thus, the Balancing Guideline deals principally with exchanges of balancing energy whereas the present initiative focusses on the exchange and sharing of balancing capacity. The latter issue is much more political than the exchange of balancing energy and closely related to other questions dealt with in the present initiative, such as regional TSO cooperation or the reservation of transmission capacities. The assessments of the two initiatives are fully coherent. Indeed, the implementation of the guidelines on electricity balancing is part of the baseline for the present impact assessment[38].

1.2.6. Other relevant instruments

Other relevant instruments are the Commission proposal for setting national targets for 2030 for the sectors outside the EU's ETS, the revision of the EU's ETS for the period after 2020, EU's competition instruments and the EU state aid rules applicable to the energy sector and clarified in the EEAG. and the decarbonisation of the transport sector initiative. The manner in which this policy context is interacting with the present initiative is explored further in section 4.2.

[38] See also Section 5.1.2 of the present impact assessment and in the Annex IV on the modelling methodology.

2. PROBLEM DESCRIPTION

2.1. Problem Area I: Market design not fit for an increasing share of variable decentralized generation and technological developments

The European Union's policy to fight global warming will require the electricity systems to shift from a generation mix that is mostly based on fossil fuels to a virtually decarbonised power sector by 2050. Indeed, with the 2030 targets agreed by the October 2014 European Council (EuCo 169/14) the share of electricity generated from renewable sources is projected to be close to 49% of total electricity produced, while their share in total net installed capacity is projected to be 62.45%[39].

Table 1: RES E % share in total net electricity generation

Year	2000	2005	2010	2015	2020	2025	2030
RES E total (TWh)	422	467	683	916	1,193	1,443	1,654
Total net generation (TWh)	2,844	3,119	3,168	3,090	3,221	3,317	3,397
RES E	15%	15%	22%	30%	37%	43%	49%

Source: PRIMES; based on EUCO27 scenario

Whereas renewable electricity can be produced by a variety of technologies, most new installed capacity today is based on wind and solar power. By 2030, this is expected to be even more pronounced.

Table 2: Share of variable RES E (solar and wind power) in RES E and total net generation

Year	2000	2005	2010	2015	2020	2025	2030
Variable RES E (TWh)	22	72	171	378	618	820	995
Total RES E (TWh)	422	467	683	916	1,193	1,443	1,654
Variable RES E in RES E	5%	16%	25%	43%	52%	57%	62%
Variable RES E in total net generation	1%	2%	5%	12%	19%	25%	29%

Source: PRIMES; based on EUCO27 scenario

The patterns of electricity production from wind and sun are inherently more variable and less predictable when compared to conventional sources of energy (e.g. fossil-fuel-fired power stations) or flexible RES E technologies (e.g. biomass, geothermal or hydropower). Weather-dependent production also implies that output does not follow demand. Consequently, there will be times when renewables could cover a very large share – even 100% – of electricity demand and times when they only cover a minor share of total consumption. While the demand-side and decentralized power storage could in theory react to the availability of renewable energy sources and even to extreme variations, current market arrangements do not enable most consumers to actively participate in electricity markets either directly through price signals or indirectly through aggregation.

[39] These figures are based on the PRIMES EUCO27 results.

While renewable technologies and individual projects differ significantly in size (from rooftop solar on households with 5 to 20 kW to several hundreds of MW for large offshore wind parks), the majority of renewable investments are developed at comparatively small scale. Given that the typical installation size of an onshore wind farm or a solar park is generally multiple[40] times smaller than of a conventional power station, the number of power producing units and operators will increase significantly. Consequently, the transition towards more renewables implies that more and more power will be generated in a decentralised way. Market roles and responsibilities will have to be adapted.

Finally, these new installations will not necessarily be located next to consumption centres but where there are favourable natural resources. This can create grid congestion and local oversupply.

The transition towards a low carbon electricity production poses a number of challenges for the cost-effective organisation and operation of Europe's power system and its electricity markets. The existing market framework was designed in an era in which large-scale, centralised power stations, primarily fired by fossil fuels, supplied passive customers at any time with as much electricity as they wanted in a geographically limited area – typically a Member State. This framework is not fit for taking up large amounts of variable, often decentralised electricity generation nor for actively involving more consumers in electricity markets.

The main underlying drivers are: (i) the inefficient organisation of short-term electricity markets and balancing markets, (ii) exemptions from fundamental market principles, (iii) consumers that do not actively engage in the market, (iv) consumers do not actively engage in the market and demand response potential remains largely untapped; and (v) distribution networks that are not actively managed and grid users are poorly incentivised.

40 The largest solar PV park in the EU is the 300 MW Cestas Park in France, http://www.pv-magazine.com/news/details/beitrag/frances-300-mw-cestas-solar-plant-inaugurated_100022247/#axzz4Cxalbrhc. The largest wind farm is the offshore farm "London array" with 630 MW distributed over 175 turbines. By comparison, the largest nuclear power plant in Europe is the Gravelines plant in France, with a net capacity of 5460MW. The largest coal-fired power station in Europe is the Polish Bełchatów plant with a capacity of 5420 MW.

2.1.1. Driver 1: Short-term markets, as well as balancing markets, are not efficiently organised

Today's short-term markets are not efficiently organised, because they do not give all resources – conventional power, renewables, the demand-side, storage – equal opportunities to access these markets and because they do not fully take into account the possible contribution of cross-border resources. The latter problem often originates from a lack of coordination between national entities and a lack of harmonisation of rules, while the former relates to the trading products themselves, e.g. their commitment period, which sometimes are too restrictive to allow for a level playing field of all kinds of resources[41].

Short-term markets play a major role in any liberalised power system due to the characteristics of electricity as a product. Electricity must be generated and transmitted as it is consumed. The overall supply and demand needs to be in balance in physical terms at any given point in time. This balance guarantees the secure operation of the electricity grid at a constant frequency. Imbalances between injections and withdrawals of electricity render the system unstable and, ultimately, may give rise to a black-out.

As a consequence, market participants need to be incentivised to have a portfolio of electricity injections into and withdrawals from the network that net-out. Market participants can adjust their portfolio by revising production and consumption plans and selling or buying electricity[42]. Efficient and liquid markets with robust price signals are crucial to guide these decisions[43].

The fact that the production patterns from weather dependent RES E can only be predicted with acceptable accuracy within hours, creates challenges for market parties and for system operation. In the absence of efficient and liquid short-term electricity wholesale markets, system operators have to take actions to balance the system and manage network congestions once the production forecasts become more precise. Moreover, operators of RES E are unable to adjust their portfolios once the production forecasts become more precise, leaving them exposed to risks and costs, when they deviate from their plans. An increasing penetration of RES E thus requires efficient and liquid short-term markets that can operate until very shortly before the time of physical delivery i.e. the moment when electricity is consumed. The entire electricity system must become more flexible, also through the progressive introduction of new flexible resources such as storage, to accommodate variations in RES E production.

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[41] EPRG Working paper 1614 (2016) "*Overcoming barriers to electrical energy storage: Comparing California and Europe*" by F. Castellano Ruz and M.G. Pollitt concludes: "*In Europe, there is a need to clarify the definition of EES, create new markets for ancillary services, design technology-neutral market rules and study more deeply the necessity of EES.*"

[42] Depending on the delivery period, bulk electricity can be traded on "spot markets" or "forward markets". Spot markets are currently mainly "day-ahead markets" on which electricity is traded up to one day before the physical delivery takes place. On "forward markets", power is traded for delivery further ahead in time.

[43] IEA "*Re-powering markets*" (2016) suggests: *"A market design with a high temporal and geographical resolution is therefore needed"*.

Current trading arrangements are however not optimised for a world in which market participants have to adjust portfolios on short notice. The manner in which the trading of electricity is arranged and the methods for allocating the network capacity to transmit electricity are organised, allow for efficient trading of electricity in timeframes of one or more days ahead of physical delivery. These arrangements befit well a world of conventional electricity production that can be predictably steered but not the new electricity landscape with a high share of renewables with limited forecasting abilities in a day-ahead timeframe.

The current market framework already envisages that these short-term adjustments can be made in intraday markets to correct. However, whilst liquidity has increased over the past few years, there remains significant scope for further increases in these markets[44]. As way of illustration, in 2014, in the intraday timeframe, only five markets in Europe had a ratio of traded energy to demand of greater than 1%[45]. Further, progress remains in connecting ('coupling') national intraday markets in the same way as day-ahead markets. This can lead to a low level of cross-border competition in intraday markets. In 2014 only 4.1% of available interconnection capacity at the intraday stage was used, compared to 40% at day-ahead.

Improving liquidity of intraday markets requires addressing various issues, including removing the barriers that today exist for trading power across borders as well as providing proper incentives to rebalance portfolios by trading until short notice before markets close. In addition, technical rules of the market (i.e. products, bid sizes, gate closure times) are often not defined with renewables or demand response in mind creating *de facto* barriers for its participation.

Specific issues include a variation in commitment periods across Europe, with some Member States choosing 15-minute and other Member States choosing 60-minute products, and the time to which market participants can trade, which can be as short as 5 minutes or, in some instances, upto several hours before real time. There is also a difference in how markets are organised: in continuously traded markets, transactions are concluded throughout the trading period every time there is a match between bids and offers. Transactions are concluded differently in auction markets, where previously collected bids and offers are all matched at once at the end of the trading period.

The last market-based measure to net out imbalances between injections and withdrawals of electricity is the balancing market. As such, the balancing market is not solely a technicality ensuring system stability but has significant commercial implications and, in turn, implications for competition. Procurement rules often fit large, centralised power stations but do not allow for equal access opportunities for smaller (decentralised) resources, renewables, demand-side and batteries. ACER's market monitoring reports revealed high levels of concentration within national balancing markets. TSOs are often faced with few suppliers or (in case of vertically integrated TSOs) procure balancing reserves from their affiliate companies. This, combined with a low degree of integration,

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[44] See Annex 2.2 for further details.

[45] Spain (12.1%) Portugal (7.6%), Italy (7.4%) Germany (4.6%) Great Britain (4.4%). ACER, *Market Monitoring Report 2015*

enables a limited number of generators to influence the balancing market outcome. Moreover, the procurement rules can lower the overall economic efficiency of the power system by creating so-called must-run capacity, i.e. capacity that does not (need to) react to price signals from other markets, because it generates sufficient revenues from balancing markets.

Beside procurement *rules*, there is a potential issue with procurement *volumes* due to national sizing of reserves. Possible contributions of neighbouring resources are not properly taken into account, thus over-estimating the amount of reserves to be procured nationally.

2.1.2. Driver 2: Exemptions from fundamental market principles

Two fundamental principles of today's market framework are that (i) market participants should be financially responsible for any imbalance in their portfolio and that (ii) the operation of generation facilities should be driven by market prices. For a number of reasons a wide range of exceptions from these principles exist today which could lead to distortions, thus diminishing market efficiency.

The principle of financial responsibility for imbalances is often referred to as balancing obligation. In many Member States, some market participants are fully or partly exempted from this obligation, notably many renewable energy but also CHP generators. Exemptions are typically granted on policy grounds, e.g. the existence of policy targets for renewables. Such a special treatment constitutes a challenge for the cost-effective functioning of electricity markets, because these technologies represent a significant share in total power generation already and are expected to further grow in importance in the forthcoming decade. For RES E, exemptions from balancing responsibility were initially justified on the basis of significant errors in production forecasts being unavoidable (as production for many RES E technologies is based on wheather) and on the absence of liquid short-term markets which would have allowed RES E generators to trade electricity closer to real time, thus reducing the error margin. Significant improvements have been made in wheather forecasts, reducing the error margin. Part of these improvements was based on financial incentives from increased balancing responsibilities[46]. Furthermore, cross-border integration and liquidity of short-term markets has improved over the last years, with further progress expected over the coming years, such as through the progressive penetration of storage, and following the present proposal. Thus, the underlying reasons for the exemption of RES E from this principle have to be revisited.

A consequence of this lack of balancing obligation is that plant operators have no incentive to maintain a balanced portfolio. The balancing obligation is typically passed on to the responsible system operator, a regulated party, meaning that their balancing costs will be socialised. This represents a market distortion and lowers the liquidity and

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[46] ENTSO-E provided figures that following the introduction of balancing responsibility in one Member States, the average hourly imbalance of PV installations improved from 11.2 % in 2010 to 7.0 % in March 2016, and the average hourly imbalance of wind improved from 11.1 % to 7.4 % over the same period.

efficiency of short-term markets as the concerned market operators do not become active on the short-term market to balance their portfolio. So the absence of full balancing responsibility is in fact a major driver preventing the emergence of liquid and efficient short-term markets. Moreover, costs arising from forecast errors for renewables are likely higher than necessary due to a lack of incentive to minimise them by short-term market operations. This creates a higher than necessary burden on consumers' electricity bills.

The principle that the operation of generation facilities should be driven by market prices is also referred to as economic dispatch. When a unit's variable production costs are below market price, it is economically efficient to dispatch it first, because the operator generates (gross) profits from selling electricity. This principle guarantees that power is produced at the lowest cost to reliably serve consumers, while taking into account operational limits. However, priority dispatch deviates from this principle, by giving certain technologies priority independent of their marginal cost. This represents a market distortion and leads to a sub-optimal market outcome.

Given the expected massive increase in share of wind and solar technologies, it is likely that unconditional dispatch incentives for these technologies will aggravate the situation, as will the fact that certain RES E technologies and often CHP have positive variable production costs. The review of priority dispatch rules for RES E is thus closely related to the review of rules on public support in the RED II. Compared to the impact on RES E from low marginal cost technologies, fully merit order-based dispatch has more significant impact on conventional generation (CHP and indigenous fuels) and high marginal cost RES E (e.g. RES E based on biomass), as these technologies will not be dispatched first under the normal merit order. Achieving merit order based dispatch will in these cases allow to use flexibility resources to their maximum extent, creating e.g. incentives for CHP to use back-up boilers or heat storage to satisfy heat demand in case of low electricity demand, and use flexible biomass generation to satisfy demand peaks rather than producing as baseload generation.

Similarly, the principle of priority access reduces system efficiency in situations of network congestion. When individual grid elements are congested, the most efficient solution is often to change the dispatch of power generation or demand located as closely as possible to the congested grid element. Priority rules deviate from this principle, forcing the use of other, potentially much less efficient resources. With sufficient transparency and legal certainty on the process for curtailment and redispatch, and financial compensation where required, priority access should be limited to where it remains strictly necessary.

R&D results[47]**:** In relation to dispatching and curtailment, the Integral project showed that load-shedding based on software tools and remote control can be a useful tool to manage grid constraints and prevent network problems. It demonstrated that load-shedding can be done on a procurement basis by the grid operator and is a viable alternative to RES E curtailment. Thus, the grid operator can find the most cost-efficient solution on market based terms as opposed to taking recourse to simply curtailing certain sources of generation.

2.1.3. Driver 3: Consumers do not actively engage in the market and demand response potential remains largely untapped

The active participation of consumers in the market is currently not being promoted, despite technical innovation such as smart grids, self-generation[48] and storage equipment that allow consumers – even smaller commercial and residential consumers – to generate their own electricity, store it, and manage their consumption more easily than ever. While more and more consumers have access to smart meters and distributed renewable energy resources such as roof-top solar panels, heat pumps and batteries, a minor share manages their consumption and these resources actively.

Large-scale industrial consumers already are active participants in electricity markets. However, the vast majority of other consumers neither has the ability nor the incentive to take consumption, production and investment decisions based on price signals that reflect the actual value of electricity and grid infrastructure. The metering and billing of consumers does not allow them to react to prices within the time frames in which wholesale markets operate. And even where technically possible, many electricity suppliers appear reluctant to offer consumer tariffs that enable this. This leads to the overconsumption/underproduction of electricity at times when it is scarce and the underutilisation/overproduction of electricity at times when it is abundant.

Indeed, current markets do not enable us to reap the full benefits of technological progress in terms of reducing transaction costs, reducing information asymmetries, and (thereby) reducing barriers to market participation for smaller commercial and residential consumers.

Periods of abundance and scarcity will increasingly be driven by high levels of RES E generation. To deal with an increased share of variable renewables generation in an efficient way, flexibility is key. Traditionally, almost all flexibility was provided in the electricity systems by controlling the supply side. However, it is now possible to provide demand side flexibility cost effectively. New technological developments such as smart metering systems, home automation, etc. but also new flexible loads such as heat pumps and electric vehicles allow for the reduction of demand peaks and, hence, significantly reduce system costs.

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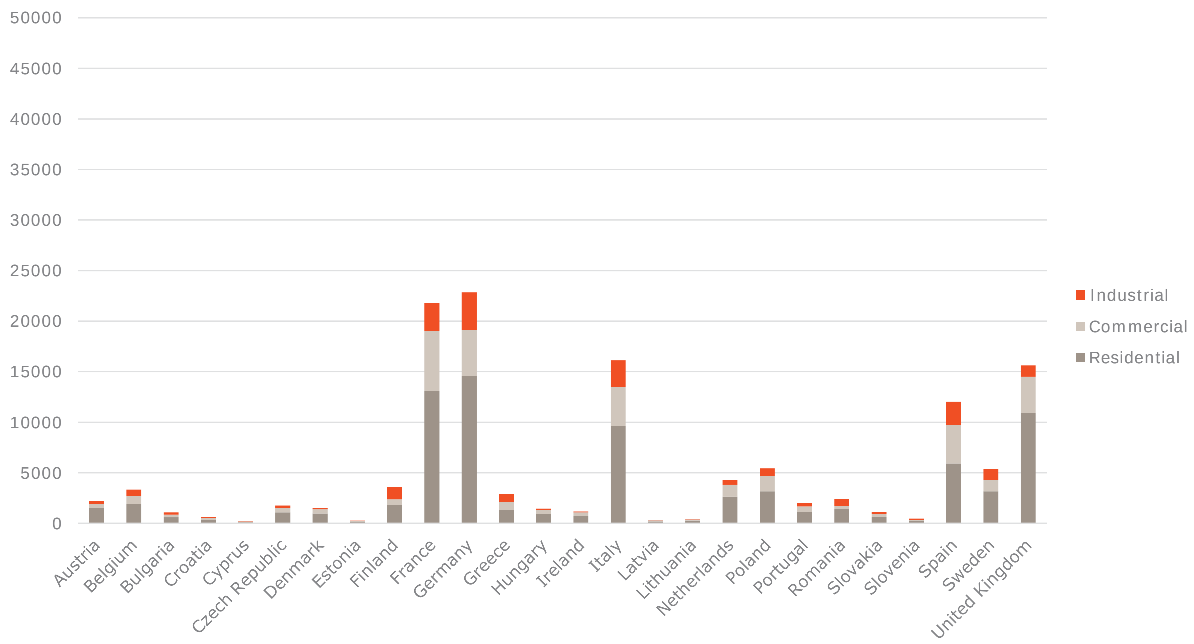
[47] Technological developments are both part of the drivers that affect the present initiative and part of the solutions of the identified problems they affect. Therefore reference is made to finding of various research and development projects that provide insights where these are pertinent. A list of the research and development projects mentioned in this box and their findings relevant to the present impact assessment is provided in Annex 8.

[48] The specific issue of self-generation and self-consumption is analysed in detail in the Impact Assessment for the RED II.

The current theoretical potential of demand response adds up to approximately 100,000 MW and is expected to increase to 160,000 MW in 2030. This potential lies mainly with residential consumers, and its increase will greatly depend on the uptake of new flexible loads such as electric vehicles and heat pumps.

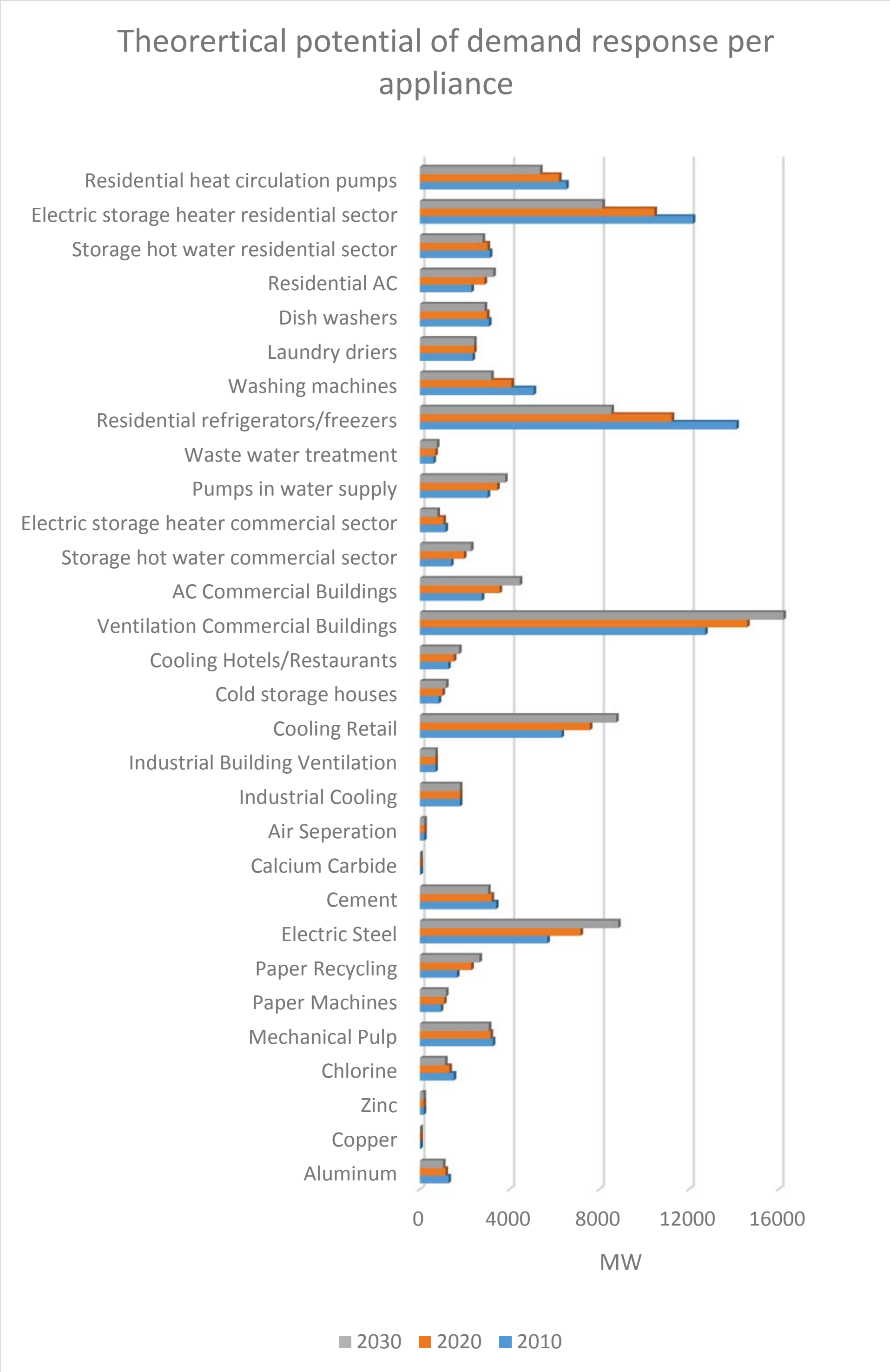
Figure 1: Theoretical demand response potential 2016 (in MW)



Source: Impact Assessment support Study on downstream flexibility, demand response and smart metering, COWI, 2016

For the industrial sector demand response is mainly related to flexible loads in electric steel makings. In the commercial sector, a high theoretical potential exist for ventilation of commercial buildings while in the residential sector mainly freezers and refrigerators, and the electric heater with storage capacity show a high theoretical potential.

Figure 2: Theoretical potential of demand response per appliance



Source: Impact Assessment support Study on downstream flexibility, demand response and smart metering, COWI, 2016

Approximately 30-40% of this potential can be considered technically and economically viable and, hence, can expected to be activated if the right technologies, incentivising mechanisms and market arrangements are in place. Demand response service providers (often referred to as aggregators) can play an important role in activating this potential by enabling smaller consumers and distributed generation in general to interact with the market and have their resources being managed based on price signals, or provide balancing or grid congestion services. These aggregators effectively reduce transaction costs and information asymmetries in the market, enabling a large number of smaller and/or distributed resources to praticipate.

Of this potential, currently only around 21,000 MW demand response is used in the market. Approx. 15,000 MW are contracted from large industrial consumers through direct participation in the market while approx. 6,000 MW come from residential consumers who are on traditional time of use tariff (usually just differentiating between day and night). Only in the Nordic markets a slow uptake of dynamic price contracts linked to the wholesale market is taking place. This shows that especially in the residential and commercial sector with a theoretical potential of more than 70,000 MW the uptake of deman dresponse is slow.

The main reasons for residential and commercial consumers not taking part in the demand response schemes are mostly technical but can also be explained by currently relative small benefits for those consumer groups:

- The technological prerequisites are not yet installed and even where smart meters are being rolled out they do not always have the functionalities necessary for consumers to take active control of their consumption;
- Dynamic electricity price contracts are only available for commercial/residential consumers in very few Member States and hence consumers do not have a financial incentive to shift consumption;
- In many Member States, third-party service providers helping consumers to manage their consumption can not freely engage with consumers and do not have full access to the markets;
- In many European markets price spreads are reletively small and price peaks either not incur often or only lead to peak prices that are slightly higher than the average price which makes demand response currently not very interesting from a financial point of view. However, with an increase in renewables generation this price spreads are likely to increase and participating in demand response will become more profitable for consumers in the future. Variable network tariffs can equally contribute to increasing the price spread;
- Consumers are more likely to participate in demand response when they have significant single loads such as electric heating or electric boilers that are easy to shift. In that respect the uptake of electric vehicles and heat pumps will also open new opportunities for consumers to engage in demand response;
- Finally, automatisation is key to untap the full potenial of demand response in the residential and commercial sector. Considering the relatively small economic benefit residential consumers are likley to realise by participating in demand response it is essential that theparticipation does not require active efforts but devices can react automatically to price signals. Hence, interoperability of smart metering systems will be crucial for the uptake of demand response.

In addition, the current design of the electricity market has not evolved to fully accomodate demand side flexibility. It was meant for a world where consumers are passive consumers of electricity that do not actively participate in the market. Hence, current market arrangements at both the wholesale and retail level often make it very difficult for demand-side flexibility to compete on a level playing field with generation:

- Similar to RES E, consumption is variable and subject to forecast errors. As a consequence, it is often infeasible for most individual customers to offer demand-response many days ahead of the moment when electricity is actually consumed
- The liquidity of intraday markets – where demand response at short notice can fetch a high price – is currently limited, providing little incentive to offer demand-side flexibility;
- Procurement timeframes for balancing reserves capacity have generally long lead times (week-, month- or year-ahead) for which demand response cannot always secure firm capacity.
- Balancing markets often require that units can offer both upward regulation (i.e. increasing power output) and downward regulation (i.e. reducing power output; offering demand reduction) at the same time, making it difficult for demand response to participate in those markets;
- And finally, product definitions make it difficult for aggregated loads to compete in many markets.

The table below summarizes in which Member States markets are open to demand response and the volume of demand response contracted. While demand response is allowed to participate in most Member States, volumes of more than 100MW can only be found in 13 Member States.

Table 3: Participation of explicit Demand Response in different markets

Member State	Demand Response in energy markets	Demand Response in balancing markets	Demand Response in Capacity mechanisms	Estimated Demand Response for 2016 (in MW)
Austria	Yes	Yes		104
Belgium	Yes	Yes	Yes	689
Bulgaria	No	No		0
Croatia	No	No		0
Cyprus	No market	No market		0
Czech Republic	Yes	Yes		49
Denmark	Yes	Yes		566
Estonia	Yes	No		0
Finland	Yes	Yes	Yes	810
France	Yes	Yes	Yes	1689
Germany	Yes	Yes	Yes	860
Greece	No (2015)	No		1527
Hungary	Yes	Yes		30
Ireland	Yes	Yes	Yes	48
Italy	Yes	No	Yes	4131
Latvia	Yes	No	Yes	7
Lithuania	unclear	No		0
Luxembourg	No information	No information		
Malta	No market	No market		
Netherlands	Yes	Yes		170
Poland	Yes	Yes	No	228
Portugal	Yes	No		40
Romania	Yes	Yes		79
Slovakia	Yes	Yes		40
Slovenia	No	Yes		21
Spain	Yes	No	Yes	2083
Sweden	Yes	Yes	Yes	666
UK	Yes	Yes	Yes	1792
Total				15628

Source: Impact Assessment support Study on downstream flexibility, demand response and smart metering, COWI, 2016

R&D results: VSync demonstrated that PV or wind generation, if equipped with a technology as demonstrated in the VSync project, can replace the inertia that large power plants possess that is needed to reduce frequency variations. Therefore, such technologies could in principle be used to provide balancing services to the TSO.

EvolvDSO has identified and worked-out the details of future roles for actors active in the management of power systems at the distribution level. The project identifies ways in which flexibility of resources connected at distribution level could be revealed, valorised, contracted and exploited by various actors of the power system. It identified roles that could be fulfilled by DSOs and by market parties and asks that these are clarified

Several European demonstration projects such as ECOGRID-EU, Integral, EEPOS, V-Sync and S3C have provided evidence that demand response is sufficiently mature from a technical point of view, while stressing the need to removing market related barriers to its deployment.

In particular, Integral and ECOGRID-EU show that valuing flexibility through price signals is possible and easy, that local assets can participate and earn money in the wholesale market, and that the economic viability depends on the value of flexibility. Integral also demonstrated that flexibility of a household's energy consumption (and hence the ability to provide demand response) was higher than initially expected, probably due to the automated response that did not require active consumer participation. ECOGRID-EU showed that a customer with manual control gave a 60 kW total peak load reduction while automated or semi-automated customers gave an average peak reduction of 583 kW.

RES E and flexible electricity systems

Demand response, like other measures that improve the degree of flexibility in the system, have an connection to the ability of RES E to finance itself in the market, through what is often referred to as the 'merit order effect'. [49] During windy and sunny days the additional electricity supply reduces the prices. Because the drop is larger with more installed capacity, the market value of variable renewable electricity falls with higher penetration rate, translating into a gap to the average market value of all electricity generators over a given period. Inflexible markets where demand and generation are non-responsive to price signals (including through measures such as priority dispatch or 'must-run' obligations) render this effect more pronounced. This effect is already visible today in certain Member States, and in the absence of measures, can be expected to become even more relevant as renewables penetration increases further.

At the one hand, this implies that as renewables are further gaining market shares in the coming decade, the regulatory framework should not only incentivise the deployment of renewables where costs are low (e.g. due to abundant wind or solar resources), but also where and when the value of the produced electricity is the highest. On the other hand, by improving the market framework in which RES E operates by rendering it more flexible, unnecesarry erosion of the value of RES E assets can be prevented.

Reference is made to the box in Section 6.2.6.3 and Section 6.2.6.4 for further information.

2.1.4. Driver 4: Distribution networks are not actively managed and grid users are poorly incentivised

Most of the time, the present regulatory framework does not provide appropiate tools to distribution network operators to actively manage the electricity flows in their networks. It also does not provide incentives to customers connected to distribution grids to use the network more efficiently. Because smaller consumers have historically participated in the broader electricity system only to a limited extent, currently no framework exists that puts such incentives in place. This has led to fears over the impact that the deployment of distributed resources could have at system-level (e.g. that the costs of upgrading the network to integrate them would outweigh their combined benefits in other terms). Moreover, the regulatory framework for DSOs, which most of the times is based on cost-plus regulation, does not provide proper incentives for investing in innovative solutions which promote energy efficiency or demand-response and fails to recognise the use of flexibility as an alternative to grid expansion.

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[49] See Hirth, Lion, *"The Market Value of Variable Renewables"*, Energy Policy, Volume 38, 2013, p. 218-236). The merit order effect is occasionally also referred to as the 'cannibalisation effect'.

With RES E being a source of electricity generation that is often decentralised in nature, DSOs are gradually being transformed from passive network operators primarily concerned with passing-on electricity from the transmission grid to end-consumers, to network operators that, not unlike TSOs, actively have to manage their grids. At the same time, technological progress allows distribution system operators to reduce network investments by managing locally the challenges that more decentralised generation brings about. However, outdated national regulatory frameworks may not incentivise or even permit DSOs to make these savings by operating more innovatively and efficiently because they reflect the technological possibilities of yesteryear. The resulting inflexibility of distribution networks significantly increases the cost of integrating more RES E generation, particulary in terms of investment.

R&D results: Reduced network investment by managing locally decentralised generation is demonstrated in European projects like: SuSTAINABLE, MetaPV, evolvDSO, PlanGridEV, BRIDGE and REServices[50].

According to EvolvDSO, flexibility procurement and activation by DSOs are not addressed in the regulatory framework in most Member States: they are not excluded in principle but not incentivised either and, because they are not explicitly addressed, this creates uncertainty for the DSO to apply them.

The REServices study has analysed the possible services that wind and solar PV energy can provide to the grid in theory but concludes that they are not able to (in the Member States analysed) due to the way the market rules are defined.

The project SuSTAINABLE demonstrated that intelligent management supported by more reliable load and weather forecast can optimise the operation of the grid. The results show that using the distributed flexibility provided by demand-side response can bring an increase of RES E penetration while, at the same time, avoid investments in network reinforcement, and this leads to a decrease in the investment costs of distribution lines and substations.

The BRIDGE project recommended that products for ancillary services should be consistent and standardized from transmission and down to the local level in the distribution network. Such harmonization will facilitate the participation of demand-side response and small-scale RES in the markets for these services, and thereby increase the availability of the services, enable cross-border exchanges and lower system costs.

Tests in the project PlanGridEV with controllable loads (demand response, electric vehicles) performed in a large variety of grid constellations have shown that peak loads could be reduced (up to 50%) and more renewable electricity could be transported over the grid compared to scenarios with traditional distribution grid scenarios. As a result, critical power supply situations can be avoided, and grids, consequently, do not call for reinforcement

Both MetaPV and EvolvDSO suggest that a DSO makes a multiannual investment plan that takes into account flexibility it can purchase from connected demand-side response or self-producers and consumers (MetaPV suggests to do this through a cost-based analysis)

MetaPV also demonstrated that remotely controllable inverters connecting PV-panels to the distribution grid can offer congestion management services to the distribution grid (in the form of voltage control obtained via reactive power modulation). This increases the capacity of the distribution grid to integrate intermittent RES by 50%, at less than 10% of the costs of 'traditional' investments in hardware such as copper.

[50] A list of the research and development projects mentioned in this box and their findings relevant to the present impact assessment is provided in Annex 8.

2.2. Problem Area II: Uncertainty about sufficient future generation investments and uncoordinated capacity markets

In light of the 2030 objectives, considerable new investment in electricity generation capacity will be required. The power sector is likely to play a central role in the energy transition. First, it has been the main sector experiencing decarbonisation since the last decade and its challenges still remain high. Second, in the near future, the power sector is expected to support the economy in reducing its dependence on fossil fuels, notably in the transport and heating and cooling sectors.

Generation capacity in the EU increased sharply from 2009 onwards due to the addition of new renewables technologies to the already existing capacity. The composition of the capacity mix progressively changed. Nuclear capacity started declining in recent years (2010-2013) due to phasing out decisions in some Member States. Other conventional capacity showed a decline in 2012-2013 as well[51].

The largest part of the required new capacity will be variable wind and solar based, complemented by more firm, flexible and less carbon-intensive forms of power generation. At the same time, in light of the ageing power generation fleet in Europe with more than half of the current capacity expected to be decommissioned by 2040[52], it is important to maintain sufficient capacity online to guarantee security of supply. The modelling results nevertheless indicate that investment needs in additional thermal capacity will be limited especially in the period 2021-2030. According to PRIMES EUCO27, about 81% of net power capacity investments will be in low-carbon technologies, of which 59% in RES E and 22% in nuclear generation[53].

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51 See on this and for further information, *European Commission*, *Investment perspectives in electricity markets*, Institutional Paper 003, July 2015, page 8. http://ec.europa.eu/economy_finance/publications/eeip/pdf/ip003_en.pdf.

52 World Energy Outlook 2015, IEA

53 The challenge to attract sufficient investment in RES E is examined in detail in the RED II impact assessment

Table 4: Investment Expenditure (including new construction, life-time extension end refurbishment) in generation capacity by technology (average over 5 year period) in MEuro'13

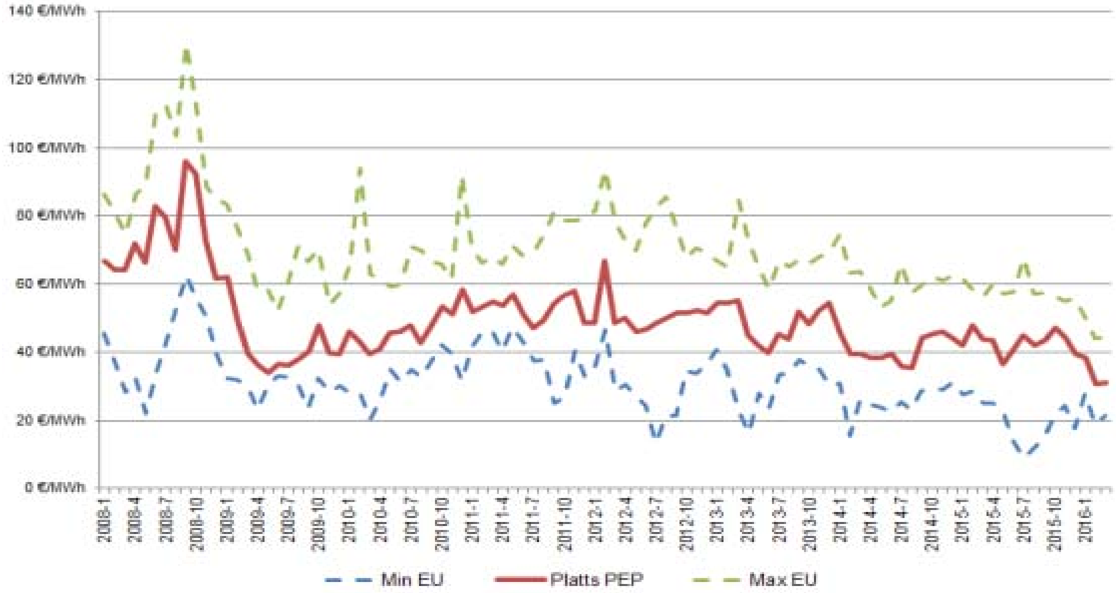
Period	2000-2005	2005-2010	2010-2015	2015-2020	2020-2025	2025-2030
Nuclear	1,502	739	270	6,291	11,011	14,312
Renewable energy	16,789	28,672	43,393	38,957	25,217	21,911
Hydro (pumping excl.)	5,995	2,557	3,289	2,239	354	633
Wind	9,238	17,095	19,614	28,553	14,059	14,219
Solar	1,556	9,019	20,487	7,870	10,581	6,728
Other renewables	-	2	3	295	223	332
Biomass-waste fired	2,626	3,438	4,157	11,779	465	433
Geothermal heat	100	90	110	182	-	-
Thermal	11,989	14,019	13,391	17,151	3,355	3,274
Solids fired	1,029	1,237	5,333	2,610	870	192
Oil fired	639	373	362	75	33	9
Gas fired	7,595	8,880	3,427	2,505	1,987	2,641
Hydrogen plants	-	-	1	-	-	-
Total (incl. CHP)	30,280	43,430	57,054	62,399	39,583	39,497

Source: PRIMES; based on EUCO27 scenario

At the same time, short-term market prices at wholesale level have decreased substantially over the past years. In parallel with high fossil fuel prices, European wholesale electricity prices peaked in the third quarter of 2008; then fell back as the economic crisis broke out, and slightly recovered between 2009 and 2012. However, since 2012 wholesale prices have been decreasing again. Compared to the average of 2008, the pan-European benchmark for wholesale electricity prices were down by 55% in the first quarter of 2016, reaching 33 EUR/MWh on average, which was the lowest in the last twelve years[54].

[54] See the "main findings" of Section 1.1 on Wholesale electricity prices from the 2016 Commission Staff Working Document accompanying the forthcoming *'Report on energy prices and costs in Europe*'.

Figure 3 on pan-European wholesale market prices



Source: Platts and European power exchanges

Prices declined for a number of reasons[55] including (i) a decrease in primary energy prices (e.g. coal, and more recently also natural gas), (ii) an increasing imbalance between the supply and demand for carbon allowances, leading to a surplus of over 2 billion allowances by 2012 and a corresponding decrease in carbon allowance prices[56], and (iii) an overcapacity of power generation facilities[57], putting a downward pressure on wholesale prices.

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55 The influence of each market factor might strongly very across different regions. For example, the share of renewables and carbon prices have strong impact on wholesale price evolution in North Western Europe, while in Central and Eastern Europe the main price driver is the share of coal and gas in the generation mix.

56 Between April 2011 and May 2013 carbon emission allowance contracts underwent a significant price fall (decreasing from 17 EUR/tCO2e to 3.5 EUR/tCO2e) reflecting the fall in demand for allowances due to the recession. Since April 2013 carbon prices have increased, reaching an average auction clearing price of €7,62/tCO2e in 2015.
(See: http://ec.europa.eu/clima/policies/ets/auctioning/docs/cap_report_201512_en.pdf).
The extent to which the carbon price impacts the wholesale power price depends on the carbon intensity of the marginal power producer.

57 In parallel with decreasing fossil fuel and carbon prices (resulting in decreasing marginal costs of electricity generation(, and the generation overcapacity, the share of renewable energy sources (wind, solar, biomass, also including hydro) has been gradually increasing over the last few years. In most of the EU countries fossil fuel costs set the marginal cost of electricity generation, being decisive for the wholesale electricity price. However, increasing share of renewables in the electricity mix, together with significant baseload generation capacities, shifted the generation merit order curve to the right, resulting in lower equilibrium price set by supply and demand. Consequently, we can say that increasing share of renewable energy sources, in an already oversupplied market, have significantly contributed to low wholesale electricity prices in the EU markets.

Overcapacity was, in turn, caused by: (i) a drop in electricity demand as electricity consumption decoupled from an already low economic growth[58], (ii) over-investments in thermal plants[59], (iii) the increasing proportion of renewables with low marginal costs driven by EU policies, (iv) barriers to decommission capacity[60], and (v) continuing improvement in the field of coupling national electricity markets[61], leading to an increased sharing of resources among Member States[62].

As a result, for most regions in Europe current electricity wholesale prices do not indicate the need for new investments into generation capacity. There are, however, doubts whether the market, as currently designed, would be able to produce investment signals in case generation capacities were needed. Independently of current overcapacities of most regions in Europe, a number of Member States anticipate inadequate generation capacity in future years and introduce capacity mechanisms at national level.

2.2.1. Driver 1: Lack of adequate investment signals due to regulatory failures and imperfections in the electricity market

The internal energy market is built on competitive (short and long-term) wholesale power markets where price signals are central to guide market participants production and consumption decisions. Short-term prices signal prevailing supply and demand

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58 Consumption of electricity in the EU decoupled from economic growth during the last few years due to energy efficiency gains.

59 Investment decisions in the electricity sector are typically taken long before returns on investment are effectively earned, due to the time to construct new power plants. At the same time, the decentralised nature of investment decision-making means that each generator has limited information about the generation capacity that competitors will make available in the coming years. The result is what has been referred to as boom-bust cycles: alternate periods of shortages and overcapacity resulting from lack of coordination in the investment decisions of competing generators.

60 In some Member States, there is an overcapacity situation that is in fact artificially extended by clear regulatory exit barriers, which in the short-term depress market prices and in the mid/long-term ruin the investment incentives.

61 In parallel, progressing market integration decreased price divergence within the EU. Indeed in the first quarter of 2008 the price difference between the most expensive and the cheapest European wholesale electricity market was 44 EUR/MWh, eight years later this difference has shrunk to 24 EUR/MWh. Based on "main findings" from 2016 costs and prices report and underlying studies, published in conjunction with the present impact assessment

62 See also Box 9 behind section 6.4.6 for more on overcapacity, market exit and prices

conditions while long-term prices are formed according to expectations about future supply and demand. Conditions, such as for example shortages or oversupply that are expected to prevail in the future will not only determine short-term (spot) prices but also impact long-term (forward, futures) prices.

In around half of Member States sales achieved at short and long term markets determine the bulk of generators' income[63]. This income is required to cover their full costs, mainly fuel, maintenance and amortisation of assets (i.e. investments). These arrangements are often referred to as energy-only markets. In the other half of Member States there are also measures (either market based or non-market based) in place to pay generators for keeping their capacity available (capacity mechanisms or '**CM**'s), regardless as to whether they are producing electricity or not[64]. For generators who operate on the market these payments represent an additional income next to their earnings on the wholesale markets for energy. Capacity payments, thus, represent additional support to maintain and/or develop capacity.

Irrespective whether generators are expected to earn their investments solely on the 'energy-only' market or whether they can also rely on additional payments for capacity, wholesale power prices are central to provide the right signals for efficient market operations. For the EU-target model[65] to function properly, prices need to be able to properly reflect market conditions[66].

Price signals and long-term confidence that costs can be recovered in reasonable payback times are essential ingredients for well-functioning market. In a market which is not distorted by external interventions, the variability of the spot price on the wholesale market, plays a role in signalling the need of investment in new resources. In the absence of the right short- and long-term price signals, it is more likely that inappropriate investment or divestment decisions are taken, i.e. too-late decisions or technology choices that turn out to be inefficient in the long run. Price differentials between different

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63 See below, figure 1 and ACER Market Monitoring Report 2014; generators may also collect additional income from offering their capabilities, including the availability of (short-term) electricity to TSO's who rely on them to manage the system (i.e. short-term balancing and ancillary Services)

64 "*Capacity mechanisms exist worldwide both in regulated and in non-regulated markets*": CIGRE paper C5-213, "*Capacity Mechanisms: Results from a World Wide Survey*", H. Höschle, G. Doorman (2016).

65 The "*Electricity Target Model*" aims at integrating wholesale power markets by harmonising the way how transmission capacity is allocated between Member States. Central to it is market coupling which is based on the, so-called, "flow based" capacity calculation, a method that takes into account that electricity can flow via different paths and optimises the representation of available capacities in meshed grids. The implementation of the target models in gas and electricity is equivalent to achieving the completion of the internal energy market.

66 Evidently, efficient market outcome also presumes that all assets are treated equally in terms of the risks and costs to which they are exposed and the opportunities for earning revenues from producing electricity i.e. they operate on a level playing field as is esually fostered by the present intiative.

bidding zones should determine where generation and demand should ideally be located,[67].

In 2013 the Commission published an assessment identifying reasons why the market may fail to deliver sufficient new investment to ensure generation adequacy[68]. These reasons are a combination of market failures and regulatory failures. For example when consumers cannot indicate the value they place on uninterrupted electricity supply, the market may not be effective performing its coordination function. Equally however, regulatory interventions, as well as the fear of such interventions, such as price caps and bidding restrictions (regardless as to whether effectively restricting price formation at that moment or only later) limit the price signal for new investments. Likewise the prices on balancing markets operated by TSOs should not undermine the price signals from wholesale markets.

Power generators and investors have argued that regulatory uncertainty and the lack of a stable regulatory framework undermine the investment climate in the Union compared to other parts of the world and to other industries.

In fact, current market arrangements often do not allow prices to reflect the real value of electricity, especially when supply conditions are tight and when prices should reflect its scarcity, affecting the remuneration of electricity generation units that operate less often but provide security and flexibility to the system.

These regulatory failures are amplified by the increasing penetration of RES E. RES E is capacity that often has a cost structure typified by low operational costs[69], resulting in more frequent periods with low wholesale prices. The variability of RES E production moreover decreases the number and predictability of the periods when conventional electricity generators are used, thereby increasing the risk profile and risk premiums of all investments in electricity resources[70]. Whereas market participants are used to hedging risks, and market trading arrangements are adapting to allow more risks to be covered, the risk profile of investments will become more pronounced. This increases the need to ensure that prices reflect the real value of electricity to ensure plants can cover their full costs, even if they are operating less frequently.

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67 See on price signals, European Commission, *Investment perspectives in electricity markets*, Institutional Paper 003, July 2015, pages 32 and following. (http://ec.europa.eu/economy_finance/publications/eeip/pdf/ip003_en.pdf

68 See also SWD(2013) 438 "*Generation Adequacy in the internal electricity market - guidance on public interventions*", Section 3 .

69 Cost structures vary according to the underlying technology deployed. In general, wind and solar technologies have very low operational costs whereas the opposite is true for biomass fuelled generation.

70 Generators' expectations about future returns on their investments in generation capacity are affected not only by the expected level of electricity prices, but also by several other sources of uncertainty, such as increasing price volatility. The increasing weight of intermittent renewable technologies makes prices more volatile and shortens the periods of operation during which conventional technologies are able to recoup their fixed costs. In such circumstances, even slight variations in the level, frequency and duration of scarcity prices have a significant impact on the expected returns on investments, increasing the risk associated to investing in flexible conventional generation technologies.

The current market arrangements are constructed around the notion of price zones delimited by network constraints. The price differences between such zones should drive investments to be located where they relieve congestion by rewarding investments in areas typified by high prices. The congestion rents collected by network operators to transport electricity from low to high price zones are meant to be used to relieve congestion by maintaining and constructing interconnection capacity.

However, today the delineation of price zones in practice does not reflect actual congestion, but national borders. This prevents the establishment of prices that reflect local supply and demand, which leads to the phenomenom of loop flows, which can reduce the interconection capacity made available for cross-border trading and leads to expensive out-of-market redispatching and significant distortions to prices and investment signals in neighbouring bidding zones. To illustrate this, ACER has estimated, in their Market Monitoring Report[71], that reductions in cross-border capacity due to loop flows resulted in a welfare loss of EUR 445 million in 2014. Further, the costs of re-dispatch and countertrading to deal with inaccurate dispatch can be high. In 2015 the total cost for redispatching within the German-Austria-Luxembourg bidding zone was approximately EUR 930 million[72]. There is also evidence that cross-border capacity is being limited in order to deal with internal contraints, again limiting cross-border trading opportunities. The impacts of this can be significant. For example, when looking at the capacity between Germany and the Nordic power system, the Swedish regulatory authority noted significant capacity limitations, concluding that these were mostly due to internal contraints, and found that losses amounted to a total of EUR 20 million per annum in Norway and Sweden[73].

A further issue that can potentially distort investment is that of network charges on generators. This includes charges for use of the network, both at distribution-level and transmission-level (tariffs), as well as the charges applied to generators for their connection (connection charges). There is significant variation across the EU on the structure of these charges, which are set at Member State-level. For instance, some Member States do not apply any tariffs to generators, others apply them based on connected capacity and others based on the amount of electricity produced. Some include locational signals within the tariff, some do not. With regards to connection charges, some calculate them based only on the direct costs of accessing the system (shallow) and others include wider costs, such as those of any grid reinforecement required (deep). Such variations can serve to distort both investment and dispatch signals.

2.2.2. Driver 2: Uncoordinated state interventions to deal with real or perceived capacity problems

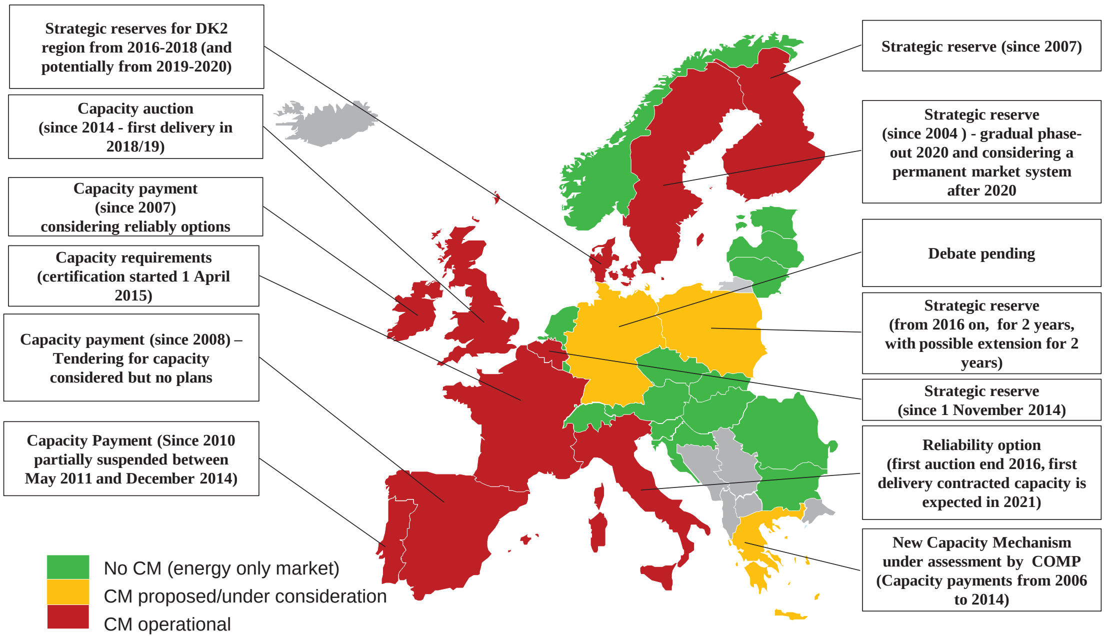
The uncertainty on whether the market will bring forward sufficient investment, or keep existing assets in the market, has, in a number of Member States, fuelled concerns about system adequacy, i.e. the ability of the electricity system to serve demand at all times.

[71] "*Market Monitoring report 2014*" (2015) ACER, Section 4.3.2 on unscheduled flows and loop flows.
[72] ENTSO-E Transparency Platform, at https://transparency.entsoe.eu/
[73] *"Capacity limitations between the Nordic countries and Germany"* Swedish Energy Markets Inspectorate (2015)

Certain Member States have reacted by introducing CMs designed to support investment in the capacity that they deem necessary to ensure a secure and acceptable level of system adequacy.

These measures often take the form of either dedicated generation assets kept in reserve or a system of market wide payments to generators for availability when needed.

Figure 4: Capacity Mechanisms in Europe – 2015



Source: "*Market Monitoring Report 2014*" (2015) ACER.

These initiatives by Member States are based on non-aligned perceptions and expectations as to the degree the electricity system can serve electricity demand at all times and a reluctance to rely on the contribution the EU system as a whole can make to the adequacy of the system of a given Member State.[74]

As reflected in the Interim Report of the Sector Enquiry[75] led by DG Competition, many existing CMs have been designed without a proper assessment of whether a security of supply problem existed in the relevant market. Many Member States have not adequately established what should be their appropriate level of supply security (as expressed by their 'reliability standard') before putting in place a CM.

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[74] Indeed, a majority of Member States expect reliability problems due to resource adequacy in the future even though such problems have been extremely rare in the past five years. Such issues have only arisen in Italy on the Islands of Sardinia and Sicily which are not connected to the grid on the mainland.

[75] See also SWD(2016) 119 final *"Interim report of the Sector Inquiry on Capacity Mechanisms"*, http://ec.europa.eu/competition/sectors/energy/state_aid_to_secure_electricity_supply_en.html

Methods of assessing resource adequacy vary widely between Member States[76], which make comparison and cooperation across borders difficult. Many resource adequacy assessments take a purely national perspective and may substantially differ depending on the underlying assumptions made and the extent to which foreign capacities[77] as well as demand side flexibility[78] are taken into account. This, in turn, means some Member States force consumers to over-pay for 'extra' capacities they do not really need.

Table 5: Deterministic vs probabilistic approaches to adequacy assessments

Adequacy Assessments							
Country	Y/N	Who?	What?	Country	Y/N	Who?	What?
Belgium	Y	TSO	Probabilistic assessment based on LOLE	Italy	Y	TSO	EENS, LOLE, LOLP and Capacity Margin are calculated
Denmark	Y	TSO	EENS, LOLE and LOLP	Poland	Y	TSO	Capacity Margin
France	Y	TSO	LOLE	Portugal	Y	TSO + Gov	Load Supply Index (supply/demand per hour)
Germany	Y	TSOs + NRA	Calculation of EENS, LOLE, LOLP and Capacity Margin	Spain	Y	TSO	Capacity Margin
Ireland	Y	TSOs + NRA	Probabilistic assessment based primarily on LOLE	Sweden	Y	TSO	EENS, LOLE and LOLP are measured

Source: European Commission based on replies to sector inquiry, see below for a description of capacity margin, LOLP, LOLE, and EENS[79]

The introduction of CMs fundamentally change wholesale electricity markets because generators and other capacity providers are no longer paid only for the electricity they generated but also for their availability. Worse however is that CMs when introduced in an uncoordinated manner can be inefficient and distort cross-border trade on wholesale electricity markets.

In the short-term, CMs may lead to distortions if their design affects natural price formation in the energy market (e.g. bidding behaviour of generators) and therefore alter production decisions (operation of power generating plants) and cross-border

[76] For more details, see annex 5.1. See also *"Generation adequacy methodologies review"*, (2016), JRC Science for Policy Report and CEER (2014), "*Assessment of electricity generation adequacy in European countries*".

[77] According to the CEER report, *"the extent to which current generation adequacy reports take the benefits of interconnectors into account varies a lot: 4 reports still model an isolated system (Norway, Estonia, Romania, and Sweden); 2 reports use both interconnected and isolated modelling (France and Belgium); 3 report methodologies are being modified to include an interconnection modelling; 9 reports simulate an interconnected system (UK, the Netherlands, Czech republic, Lithuania, Finland, Belgium and Ireland, while France and Italy use both methods)."*

[78] According to the CEER report, *"only 3 countries include demand response as a separate factor in their load forecast methodology i.e. the UK, France and Spain. In Norway and Finland, the contribution from demand response is not included as separate factor, but peak load estimation is based on actual load curves which include the effect of demand response. Sweden does not consider demand response, and do not assume that consumers respond to peak load in their analysis."*

[79] See annex 5.1 for the definition of the different methodologies.

competition. For instance, a possible distortion is when generators in a market applying a CM, receive (capacity) payments which are determined in a way that affects their electricity generation bids into the market, while in a neighbouring "energy-only" market generators do not. This may tilt the playing field for generators on either sides of the border. Another example might be if strategic reserves (a particular form of CMs) are dispatched 'too-early' impeding the market's ability to establish equilibrium between supply and demand. This can cause or contribute to a 'missing money' problem as strategic reserves would outcompete existing (or future) generators who, at least partly, rely on scarcity rents to cover their costs.

CMs may also influence investment decisions (investment in plants and their locations), with potential impacts in the long term. If contributions from cross-border capacity are not appropriately taken into account, they may lead to over-procurement of capacity in countries implementing CMs, with a detrimental impact on consumers.

CMs may also cause a number of competition concerns. In this respect, the Sector Inquiry identifies substantial issues in relation to the design of CMs in a number of Member States. First, many CMs do not allow all potential capacity providers or technologies to participate, which may unnecessarily limit competition among suppliers or raise the price paid for the capacity[80].

Second, capacity mechanisms are also likely to lead to over-compensation of the capacity providers – often to the benefit of the incumbents – if they are badly designed and non-competitive. In many Member States the price paid for capacity is not determined through a competitive process but set by the Member State or negotiated bilaterally between the Member State and the capacity provider. This creates a serious risk of overpayment[81].

Third, the inquiry revealed that capacity providers from other Member States (foreign capacity) are rarely allowed to directly or indirectly participate in national CMs[82]. This leads to market distortions as additional revenues from CMs remain reserved to national companies. This is particularly problematic in case of dominant national incumbents whose dominant position may even be strengthened by a national CM.

Lastly, although there is a challenge to design penalties that avoid undermining electricity price signals which are important for demand response and imports, where

80 In some cases, certain capacity providers are explicitly excluded from participating or the group of potential participants is explicitly limited to certain providers. In other cases, Member States set requirements that have the same effect, implicitly reducing the type or number of eligible capacity providers. Examples are size requirements, environmental standards, technical performance requirements, availability requirements, etc.

81 In Spain for example, the price for an interruptibility service almost halved after a competitive auction was introduced.

82 For example, Portugal, Spain and Sweden appear to take no account of imports when setting the amount of capacity to support domestically through their CMs. In Belgium, Denmark, France and Italy, expected imports are reflected in reduced domestic demand in the CMs. The only Member States that have allowed the direct participation of cross-border capacity in CMs are Belgium, Germany and Ireland. For more details, see annex 5.2.

obligations are weak and penalties for non-compliance are low, there are insufficient incentives for plants to be reliable.

All in all, the Sector Inquiry highlights that "*a patchwork of mechanisms across the EU risks affecting cross-border trade and distorting investment signals in favour of countries with more 'generous' capacity mechanisms. Nationally determined generation adequacy targets risk resulting in the over-procurement of capacities unless imports are fully taken into account. Capacity mechanisms may strengthen market power if they for instance, do not allow new or alternative providers to enter the market. Capacity mechanisms are also likely to lead to over-compensation of the capacity providers – often to the benefit of incumbents – if they are badly designed and non-competitive."* All of these issues can undermine the functioning of the internal energy market and increase energy costs for consumers.

As reflected in the Sector Inquiry, the heterogeneous development of capacity mechansims has led to fragmented markets across the EU. The Sector Inquiry highlights that "*the different types of capacity mechanisms are not equally well suited to address problems of security of supply in the most cost effective and least distortive way*".

The Sector Inquiry concludes that capacity payment schemes are generally problematic as they risk over-compensating capacity providers because they rely on administrative price setting rather than competitive allocation procedures. The risk for overcompensation is lower for market-wide and volume-based schemes and strategic reserves. What matters is the design of the support scheme, which can make it more or less distortive.

Several stakeholders have proposed to address investment uncertainty by dedicated regulatory provisions encouraging and clarifying the use of long-term contracts ('LTC's) between generators and suppliers or consumers[83]. They argue that such rules could help mitigating the investment risk for the capital-intensive investments required in the electricity sector, facilitating access to capital in particular for low-carbon technologies at reasonable costs.

While mandatory LTCs may involve a risk transfer to consumers unless they are certain they will have enduring future electricity demand, such contracts may allow them to benefit from less volatile retail prices as electricity would be purchased long time ahead of delivery. In terms of market functioning, it has to be stressed that current EU electricity legislation does not discourage the conclusion of long-term electricity purchase contracts. Even absent dedicated legislation, LTCs between a buyer and seller to exchange electricity on negotiated terms, can anyway be freely agreed on by interested parties without any need for further intervention by governments or regulators. Tradable wholesale contracts are already available to market parties (albeit with limited liquidity for contracts of more than three years[84]). A dedicated framework for hedging price risks

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[83] See e.g. submissions to the Commission's market design consultation from a limited number of generation companies and from energy-intensive industries.

[84] See for further information, *CEPS Special Report*, The EU power sector needs long-term price signals, No. 135/April 2016, page 9.

over longer terms has just been created with the EU Guideline on Forward Trading ("FCA Guidelines"). The only regulatory restriction to the use of LTCs may result, in exceptional situations[85], from EU Treaty rules on competition law (e.g. if they are used by by dominant companies to prevent new market entry).

It may also be noted that experience has shown that regulatory encouragement of LTCs under EU law may also entail the risk of "lock-in risk" in the fast developing electricity markets[86].

Options suggested to facilitate long-term contracting include (i) socialising the costs of guaranteeing delivery of bilateral contracts (to reduce the default risk) or (ii) introducing long-term contracts with a regulated counterparty. Both models might, however, be considered to be capacity mechanisms and would have to be scrutinised under the relevant State aid rules.

2.3. Problem Area III: Member States do not take sufficient account of what happens across their borders when preparing for and managing electricity crisis situations

In spite of best efforts to build an integrated and resilient power system, electricity crisis situations may occur. Whilst most incidents are minor[87], the likelihood of larger-scale incidents affecting the European electricity system might well be on the rise due to extreme weather conditions[88], climate change (giving rise to extreme and unpredictable weather conditions, which already today constitute a major challenge to electricity systems)[89], fuel shortage[90] and a growing exposure to cybercrime and terrorist attacks in

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85 It should be noted that there is extensive guidance and case practice on the interpretation of Article 81 and 82 with respect to long-term energy contracts available.

86 The fast changing electricity markets may require different generation solutions than today (e.g. due to new storage technology). See also the example of guaranteeing revenues for solar power producers for timeframes ten years ago which proved to be higher than necessary in retrospective due to technological developments.

87 In 2014 ENTSO-E identified over 1000 security of supply incidents. Most of these were minor but there were some more serious disturbances, for example storms on 12 February 2014 leaving 250,000 homes in Ireland without power.
See: https://www.entsoe.eu/Documents/SOC%20documents/Incident_Classification_Scale/151221_ENTSO-E_ICS_Annual_Report_2014.pdf

88 Extreme weather events are likely to affect the power supply in various ways: (i) thermal generation is threatened by lack of cooling water (as shown e.g. in summer 2015 at the French nuclear power stations Bugey, St. Alban and Golfech); (ii) heat waves cause high demand of air conditioning (which e.g. resulted in price peaks in Spain in late July 2015 when occurring in parallel with low wind output); (iii) heat waves affect grid performance in various ways, e.g. moisture accumulating in transformers (which e.g. lead to blackouts in France on June 30th 2015) or line overheating (leading to declaration of emergency state by the Czech grid operator CEPS on July 25th in 2006) (source: *European Power Daily, Vol. 18, Issue 123* (2016), S&P Global, Platts).

89 "*Delivering a secure electricity supply on a low carbon pathway*", Energy Policy no 52. 55-59 (2013), Boston, Andy.

90 One example proving that such risks should be taken into account is the shortage of anthracite coal in Ukraine in June 2016 due to the political situation in Ukraine affected the rail transport of coal. As several Ukrainian nuclear power units were offline for maintenance in parallel, the responsible ministry called for limiting power consumption as preventive measure. (Source: *European Power Daily, Vol. 18, Issue 123* (2016), S&P Global, Platts).

Europe. Already in 2014 a series of cyberattacks by the so-called "*Energetic Bear*" targeted several energy companies in Europe and US, highlighting the increasing vulnerability of the energy sector[91].

Where crisis situations occur, they often have a cross-border effect. Even where incidents start locally, they may rapidly proliferate across borders. Thus, a black-out in Italy in 2003 due to a tree flashover affected the electricity systems of its neighbouring states as well, and in 2006 the tripping of an electricity line by a cruise ship in Germany affected 15 million people and had an impact on the entire continental power system[92].

Crisis situations may also affect several Member States at the same time as it was the case during the prolonged cold spell in February 2012[93], which led to a series of uncoordinated emergency measures across Europe. Given the increasing interconnectivity of the EU's electricity systems and linkage of electricity markets, the risk of electricity crisis situations simultaneously affecting several Member States are set to further rise[94].

It should be noted that risks of cross-border electricity incidents do not stop at the European Union's borders, given increasing links between the electricity systems of EU Member States and those of some of its neighbours (e.g., synchronisation with Western Balkans, common infrastructure projects between e.g., Italy-Montenegro, Romania-Moldova, Poland-Ukraine).

Given the key role of electricity to society, electricity crisis situations entail serious costs – both economically and for the society at large[95].

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91 On 23 December 2015, a cyberattack in Ukraine led to serious power cuts affecting more than 600.000 households.

92 The Italian blackout on 28/09/2003, due to a tree flashover, affected 55 million people in Italy, Switzerland, Austria, Slovenia and Croatia. It led to a black-out situation to up to 24 hours and interrupted energy of 17 GWh.

93 The first two weeks of February 2012 saw a prolonged colder-than-usual weather period consistently with 12 degrees Celsius below winter average and reaching historically low temperatures exceeding 1 in 20 climatic conditions.

94 METIS simulation shows that the better integration of the markets would result in a propagation of the stress hours across Member States. Additionally, the stress hours would be concentrated in periods affecting simultaneously several Member States.

95 The economic impact of large scale blackouts could be estimated in billions. Thus, for instance, a blackout in France on 26 December 1999 due to storms of unprecedented violence with devastating effects, affected 3.5 million households (which corresponds to about 10 million people losing their electricity supply) and entailed an economic cost of EUR 11.5 billion and interrupted energy estimated in 400 GWh.
Recent simulations show that the damages as consequence of the power outages of 5 hours in a border region between Belgium, France and Germany to all of the economic sectors would amount to 1 billion Euro. www.blackout-simulator.com; simulation of a blackout in following NUTS regions: FR21 Champagne-Ardenne, FR41 Lorraine, FR42 Alsace, BE34 Prov. Luxembourg, BE35 Prov. Namur , DEC0 Saarland, DEB Rheinland-Pfalz, FR30 Nord - Pas-de-Calais, BE32 Prov. Hainaut, BE25 Prov. West-Vlaanderen, FR22 Picardie, BE31 Prov. Brabant Wallon, BE23 Prov. Oost-Vlaanderen, DE1 Baden-Württemberg.

Both when preparing for and dealing with crisis situations, Member States take very different approaches and tend to focus on their national territories and customers only, ignoring the possible assistance of and the impact on neighbouring countries and customers. This entails serious risks for security of supply and can also lead to undue interferences with the internal energy market.

2.3.1. Driver 1: Plans and actions for dealing with electricity crisis situations focus on the national context only

First, whilst most Member States have plans to prevent and deal with electricity crisis situations, the content and scope of these plans varies considerably and plans tend to focus on the national situation only[96]. Cross-border cooperation in the planning phase is scarce and where it takes place at all, it is often limited to cooperation at the level of TSOs[97]. This is largely due to a regulatory failure: the existing EU legal framework does not prescribe a common approach, and rules and structures for cross-border co-operation are almost entirely absent[98]. Cross-border cooperation is also hindered by divergent national rules. Cooperation with Member States outside the EU is even more limited.

Further, where crisis situations do arise, Member States also tend to react on the basis of their own national set of rules, and without taking much account of the cross-border context. Evidence shows, for instance, that Member States have different concepts of what an emergency situation is and entails[99], and who should do what and when in such

96 Source: Risk Preparedness Study - "*Review of current national rules and practices relating to risk preparedness in the area of security of electricity supply*" (2016), VVA Europe, Spark Legal Network, study prepared for DG Energy. https://ec.europa.eu/energy/sites/ener/files/documents/DG%20ENER%20Risk%20preparedness%20final%20report%20May2016.pdf

97 There are examples of existing regional co-operation involving national authorities, e.g. among the Nordic countries in the framework of Nord-BER (Nordic Contingency Planning and Crisis Management Forum). However, this co-operation is mainly restricted to the exchange of best practices.

98 See the results of the evaluation, attached as Annex VI.

99 For instance the concept of 'emergency' is not defined in all Member States and where they exist, definitions diverge.

situations. In particular, there is considerable uncertainty and divergence as regards what public authorities can do in emergency situations[100].

The fact that Member States tend to adopt national, 'going alone' approaches when preparing for and managing crisis situations stands in strong contrast with the reality of today's interconnected electricity market, where the likelihood of crisis situations affecting several Member States at the same time, is on the rise.

Where crisis situations stretch across borders (or have the potential of doing so), joint action is needed, as well as clear rules on who does what, and when, in a cross-border context. Uncoordinated actions and decisions in one Member State (for instance on what to do to prevent a further deterioration of a crisis situations or on where to shed load, when and to whom), can have serious negative effects:

For instance, as to date, several Member States still legally foresee 'export bans' (curtailing interconnectors) in times of crisis[101]. This undermines the proper functioning of markets and can seriously aggravate security of supply problems in neigbouring Member States, who might no longer be able to ensure that electricity is delivered to those that need it most. The reverse situation is also true: where in a crisis situation an interconnected state does not restrict its own electricity consumption, it risks propagating the crisis situation beyond its own borders.

The dangers related to a purely national, inward-looking management of electricity crisis situations, are illustrated by an incident that occurred during a prolonged cold spell in February 2012[102]. Confronted with a situation of unexpected shortage, one Member State

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[100] This is for example the case of France, where the Government may *"take temporary measures to attribute or suspend exploitation authorizations of electricity infrastructures"*. In Portugal, the Minister for Energy can adopt transitory and temporary safeguard measures which include the use of fuel reserves and the imposition of demand restrictions.

[101] One Member State specifically includes a legal provision on export bans in its legislation; eleven more Member States include forms of export restrictions in national law, TSO regulations or multilateral agreements. (Source: Risk Preparedness Study - "*Review of current national rules and practices relating to risk preparedness in the area of security of electricity supply*" (2016), VVA Europe, Spark Legal Network, study prepared for DG Energy).

[102] Another example where domestic consumption was prioritized over exports occurred in the Nordic region over the winter 2009/2010, where the region experienced a scarcity situation (in fact a series of them that lead to three price spikes: on December 17, January 8 and February 22) with prices reaching 1000 EUR/MWh. The initial cause was the loss of approximately 5000 MW of Swedish nuclear capacity. Maintenance on these plants over the summer was not completed on time, and so the plants were functioning at diminished capacity (61% of normal operating capacity, on average) into the winter Production reached a minimum on December 18, driving prices to the technical limit. This coincided with a winter that was already colder that average. The limited nuclear capacity continued for a period of a few weeks, and on January 8th was exacerbated by a reduction in transmission capacity between Norway and Sweden to 0MW because of higher than anticipated demand in Oslo. The Norwegian TSO, Statnett, decided to prioritise domestic consumption over exports by eliminating the interconnector. Finally, on February 22, continued low nuclear production combined with low hydro reservoirs in Norway led to a general state of limited generation capacity. Statnett again reduced transmission capacity (not to 0 MW but to 150 MW) and prices were again pushed to 1000 EUR/MWh or higher. Source: IEA (2016): *Electricity Security Across Borders. Case Studies on Cross-Border Electricity Security in Europe.*

decided to resort to an export ban in an effort to protect its national consumption. This aggravated however problems in other, neighbouring Member States, who in turn also resorted to export bans. The ensuring cascade of export bans seriously imperiled security of supply in an entire region of Europe[103].

Purely national approaches to crisis prevention and management can also lead to premature (and therefore unnecessary) market interventions, such as for instance a premature recourse to an emergency extra reserve capacity, or to a demand interruption scheme.

Finally, different approaches to crisis prevention and management might also lead to cases of 'under-protection. For instance, where Member States do not take the measures needed to prevent (e.g., cyber-incidents), the entire region or even synchronous area is likely to suffer. A similar problem might arise if Member States do not take the measures necessary to protect assets that are critical from a security of supply perspective against possible take-overs by foreign entities, in circumstances in which such take-overs could lead to any undue political influence. Experience with recent take-overs (or planned take-overs) of certain strategic energy assets in Europe shows that such risks are serious, notably where the buyer is controlled by a third country. At this stage however, Member States address this issue from a purely national perspective, based on national rules,[104] without taking necessarily account of the wider European implications possible problems could have. This could lead to situations wherein some Member States take foreign ownership risks too lightly, whilst other Member States might overreact.[105]

Evidence shows that in an inter-connected market, stronger co-operation on how to prevent and manage crisis situations brings clear benefits: it leads to a better security of supply overall, at a lesser cost. The recent METIS results[106] point in this direction, as well as experiences with a few voluntary arrangements in place in parts of Europe[107].

2.3.2. Driver 2: Lack of information-sharing and transparency

Today, national plans to prepare for crisis situations are not always public, nor shared across Member States[108]. It is not clear who will act in crisis situations, and what the

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[103] Export limitations were imposed by Bulgaria on 10 February, by FYROM on the 13 February, by Bosnia Herzegovina on 14 February, by Greece on 15 February and by Romania on 16 February.

[104] An increasing number of Member States adopt so called 'foreign investment screening laws', covering notably changes of control over strategic energy assets.

[105] See also the *Impact Assessment accompanying the proposal for a Regulation concerning measures to safeguard security of gas supply and repealing Council Regulation 994/2010* (SWD (2016) 25 final.

[106] See Section 6.3.3. (Impact of policy Option 2).

[107] For example, a co-operation agreement worked out amongst Nordic countries contains detailed arrangements on how to deal with situations of simultaneous crisis, e.g., on curtailment sharing.

[108] Nine Member States keep Risk Preparedness Plans confidential, eight make them public and eleven others have a mixed framework with some measures being released and others being kept confidential. (Source: Risk Preparedness Study - "*Review of current national rules and practices relating to risk preparedness in the area of security of electricity supply*" (2016), VVA Europe, Spark Legal Network, study prepared for DG Energy).

roles are of the different actors (governments, TSOs, DSOs, NRAs). This makes any cross-border co-operation in times of crisis very difficult[109].

In addition, Member States do not systematically inform each other or the Commission when they see crisis situations emerge. In fact, whilst ENTSO-E's seasonal outlooks[110] already point at the likelihood of upcoming crisis situations in Europe, Member States affected by such crisis situations do not systematically communicate on actions they intend to take, nor on the possible effect of such actions on the functioning of the internal market or the electricity situation in neighbouring Member States. In fact, in spite of the fact that Member States are legally obliged to notify the Commission in case they take 'safeguard measures', such notifications have been very rare, and tend to take place *ex post* (e.g., Poland in 2015)[111].

Likewise, there is no systematic exchange of information on how past crisis situations have been handled.

Such lack of information-sharing and transparency limits the capacity of reaction of potential Member States affected, may lead to premature interventions in the market, and reduces the possible benefits that cooperation can bring.

In addition, even though the Electricity Coordination Group could be used as a tool to discuss how to prevent and mitigate crisis situations[112], this does not happen in practice, in the absence of clear and proper roles given to the group, and clear obligations on Member States to report on how they address electricity crisis situations, both *ex ante* (before incidents occur) and *ex post*.

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109 A recent simulation of an electricity crisis situation across Europe, showed that Member States were neither adequately equipped to deal with the crisis nor the consequences thereof, largely because it was not clear who did what in which country on what moment (cf. results of VITEX 2016 exercise, organized by the Dutch Ministry: https://english.nctv.nl/currenttopics/news/2016/successful-international-exercise-vitex.aspx?cp=92&cs=38). VITEX 2016 is an international table top exercise on the improvement of Critical Infrastructure Protection. The main goal of the exercise is to strengthen the ties between EU Member States on this subject. VITEX 2016 aims to create a shared understanding of what the Critical Infrastructures within Member States are and how European cooperation can contribute to improve the resilience of Critical Infrastructure.

110 ENTSO-E has the obligation to carry out seasonal outlooks as required by Article 8 of the Electricity Regulation. The assessment explores the main risks identified within a seasonal period and highlights the possibilities for neighbouring countries to contribute to the generation/demand balance in critical situations.

111 Poland activated a crisis protocol mid-August 2015 allowing the TSO to restrict power supplies to large industrial consumers (load restrictions did not apply however to households and some sensitive institutions such as hospitals). Poland notified the adoption of these measures under Article 42 of the Electricity Directive one month after.

112 According to Article 2 of Commission Decision of 15 November 2012 setting up the Electricity Coordination Group, the Group shall in particular *"promote the exchange of information, prevention and coordinated action in case of an emergency within the Union and with third countries"*.

2.3.3. Driver 3: No common approach to identifying and assessing risks

Whilst all Member States identify and assess risks that can affect security of supply, there are many different understandings of what constitutes a 'risk' and methods for assessing and addressing such risks vary considerably.

Different risks are assessed in different ways[113], by different people[114], and in different time horizons[115].

There is also no common agreement on what indicators to use to assess security of supply overall[116].

In the absence of a common approach to risk identification and assessment, it is difficult to get an exact picture of what risks are likely to occur, in a cross-border context. This, in turn, seriously hampers the possibility for relevant actors – TSOs, NRAs, Member States – to prevent and manage crisis situations in a cross-border context.

2.4. Problem Area IV: The slow deployment of new services, low levels of service and questionable market performance on retail markets

Retail markets for energy in most parts of the EU suffer from persistently low levels of competition and consumer engagement. In addition, whilst information technology now offers the possibility of greatly improving the consumer experience and making the market more contestable, realising these benefits could be hampered by the lack of a data-management framework that unlocks the full benefits of smart energy management to all market actors – incumbents and new entrants alike.

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[113] There exists a patchwork of types of risks covered under the assessments in the Member States. The level of detail in which the types of risks are described varies and a high level of detail was found in three Member States. In five Member States the types of risks to be assessed are not or very generally described. (Source: Risk Preparedness Study - "*Review of current national rules and practices relating to risk preparedness in the area of security of electricity supply*" (2016), VVA Europe, Spark Legal Network, study prepared for DG Energy).

[114] The combination of national entities (TSOs, the competent Ministries, the NRAs and the DSOs) responsible for risk assessment and the division of their roles, which are often defined by law, vary across the Member States. TSOs play a major role in the assessment of risks in a majority of the countries. (Source: Risk Preparedness Study - "*Review of current national rules and practices relating to risk preparedness in the area of security of electricity supply*" (2016), VVA Europe, Spark Legal Network, study prepared for DG Energy).

[115] Time horizons covered can vary from one year to fifteen years. Moreover, some Member States set no limits of validity for their measures, others have a system of continuous updates whist at least eleven countries do not specify time horizons. (Source: Risk Preparedness Study - "*Review of current national rules and practices relating to risk preparedness in the area of security of electricity supply*" (2016), VVA Europe, Spark Legal Network, study prepared for DG Energy).

[116] A wide variety of metrics and methodologies to assess security of supply and system adequacy is used, but there is no specific reference to an economic value of adequacy (in particular to VOLL). Several Member States have established standards, generally in terms of LOLE targets. However, information is lacking on the criteria (if any) used to establish those standards. Metrics and standards have been set through subjective decision, despite the evident fact that setting a standard (and the generation or transmission capacity necessary to achieve that standard) will have an economic impact on consumers. (Source: "*Identification of Appropriate Generation and System Adequacy Standards for the Internal Electricity Market"* (2016), AF Mercados, E-Bridge, REF-Em, study prepared for DG Energy).

These closely inter-related issues result in **the slow deployment of innovative products that would help to make the electricity system function better in today's changing context, as well as excessive prices for some end-consumers and/or poor levels of service.**

R&D results: Retail level innovative products and services such as dynamic pricing, self-consumption incentives, and local flexibility and energy markets, have been tested in European projects, EEPOS, ECOGRID-EU, Grid4EU, INTrEPID, INCREASE, DREAM, Integral[117].

For example, ECOGRID-EU showed that the highest cost is in the installation of the automation technologies, control systems and sensors in the household. These costs could be virtually zero in the future when appliances are connected anyway.

Integral states that large scale implementation of demand-side response services based on a market for flexibility requires standardised solutions (for the communication of the devices (smart meters and devices controllers…) and for the framework within which market players communicate to each other) to reduce the cost per household and to lower the price of the smart energy services.

2.4.1. Driver 1: Low levels of competition on retail markets

Competition on retail markets is multifaceted, and recent trends in several indicators suggest that it can be improved in many Member States.

The price of energy for end consumer can be broken down into three main components: i) energy, ii) network and iii) taxes and levies. The energy component typically includes cost elements such as the wholesale price of the commodity and various costs of the supply companies, including their operating costs and profit margins. The network component mainly consists of transmission and distribution tariffs. It might also include further cost elements such as ancillary services. The taxes & levies component includes a wide range of cost elements that significantly vary from country to country. Levies are typically designated to specific technology, market or socially bound policies, while taxes are general fiscal instruments feeding into the state budget. On average in the EU in 2015 energy made up 36% of the final household consumer price, the network component 26%, and taxes and levies 38%.

117 A list of the research and development projects mentioned in this box and their findings relevant to the present impact assessment is provided in Annex 8.

In spite of falling prices on wholesale markets (analysed earlier), overall electricity prices for household consumers rose steadily between 2008 and 2015 at an annual rate of around 3%. This trend was largely driven by increased network charges, taxes and levies[118], the various causes of which have been touched upon in the preceeding sections: the over reliance of RES E assets on government support due to barriers to fully participating in all markets; inflexible distribution networks that increase the cost of integrating RES E; and fragmented balancing markets that increase the costs of ancillary services, amongst others.

However, a proxy for mark-ups[119] on the energy component of consumer bills in several Member States also seem to be higher than could be expected, posing questions about the extent of price competition. Indeed, whereas there has been a significant reduction in wholesale prices between 2008 and 2015, the nominal level of the energy component of household electricity bills actually increased in 13 Member States during this period[120]. In these countries, the fall in wholesale prices has not translated into a reduction in the energy component of retail prices despite the fact that this is the part of the energy bill (representing around 36% of average household prices) where energy suppliers should be able to compete.

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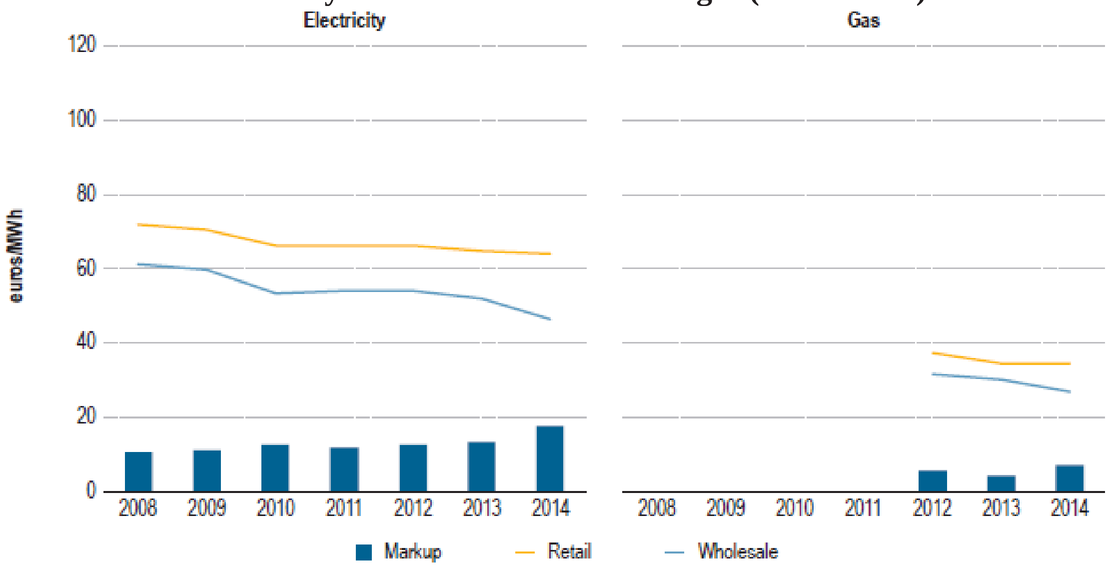
118 The average network component in consumer bills has increased by 25% since 2008, and cost EU households 5.45 euro cents per kWh in 2015. Taxes and levies increased by 70% in the same period, and stood at 7.92 euro cents per kWh in 2015. Energy taxation is not fully harmonized at the EU-level. Source: DG ENER data.

119 As defined in "*Market Monitoring report 2014*" (2015) ACER, http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015, pp. 288-295. This proxy essentially measures the relationship between the wholesale price and the energy component of the retail price. However, other factors apart from the mark-up may affect this relationship, notably including a higher proportion of fixed charges in wholesale prices.

120 DG ENER Data.

Figure 5: Relationship between the wholesale price and the energy component of the retail price in household segments in countries with non-regulated retail prices from 2008 to 2014 for electricity and from 2012 to 2014 in gas (EUR/MWh)



Source: ACER Database, Eurostat, NRAs and European power exchanges data (2014) and ACER calculations. Note: Gas data are available only for the period 2012-2014.

Abnormally low mark-ups are equally problematic as they make it difficult or impossible for a new supplier to compete against an incumbent. A reasonable mark-up is necessary for a new entrant to cover consumer acquisition and retention costs which are higher than those of the incumbent who usually retains the most loyal ('sticky') customers. Mark-ups that are too low and low levels of competition can be observed in several markets with regulated prices (developed further on the next page)[121].

As for non-price competition, whilst sampling data from European capitals suggest that 'choice' for consumers in European capitals widened in recent years, a closer inspection reveals that this has largely been driven by just two products – 'green' and dual-fuel (electricity + gas) tariffs[122]. The offer and uptake of other, more innovative consumer products, such as aggregation services or dynamic price tariffs linked to wholesale markets[123], remains limited.

Facilitating competition can be seen as means of improving consumer satisfaction. However, the data indicate that there is clearly scope for improvement in this dimension, too. According to the 2016 edition of the Commission's Consumer Scoreboard – a comprehensive study measuring consumer conditions – electricity services rank 26th and gas services 14th among the 29 markets for services across the EU. Indeed, the total detriment to EU electricity consumers[124] has recently been quantified at over EUR 5

[121] Based on Annex 5, "*Market Monitoring Report 2014*" (2015) ACER and VaasaETT 2015
[122] Source: ACER database.
[123] See also the evaluation as regards Demand Response.
[124] Consumer detriment involves consumers suffering harm or damage. Research for the Commission has suggested the following two definitions of consumer detriment, for use in different policy contexts:

billion annually[125]. Both markets can therefore be considered low performing from the consumer standpoint.

High levels of market concentration also suggest that competition could be improved: The cumulative market share of the three largest household suppliers (CR3) is greater than 70% in 21 out of 28 Member States for electricity and in 20 out of 28 Member States for gas. CR3 values above 70% are indicative of possible competition problems.

Also significant is the fact that some form of non-targeted price regulation for electricity and/or gas still exists in 17 out of 28 Member States[126]. The regulation of electricity and gas prices may result in an environment that strongly impairs healthy competition, particularly in terms of the level of customer service, or the development and provision of innovative new services that consumers would be willing to pay extra for. Reliance on the government to set prices can result in consumer disengagement. In addition, regulatory intervention in price setting can have a direct impact on suppliers' ability to offer products that are differentiated in terms of pricing-related aspects – dynamic price tariffs that reflect the minute-by-minute fluctuations on wholesale markets, for example.

When justifying price regulation Member States cite the need to protect the vulnerable and energy poor along with the need to protect all customers against the risk of market abuse. Around 10.2% of the EU population might be affected by the problem of energy poverty, based on a proxy indicator measuring "*the inability to keep home adequately warm*"[127]. If energy prices continue to increase, it is likely that energy poverty across the EU will increase and therefore more pressure to maintain energy price regulation.

Under the existing provisions in the Electricity and Gas Directive, Member States have to address energy poverty where identified. The evaluation of the provisions found important shortcomings stemming from the unclarity of the term *energy poverty*, particularly in relation to consumer vulnerability, and the lack of transparency with regards to the number of households suffering from energy poverty across Member States.

Addressing the issue of energy poverty through blanket price regulation can be disproportionate as it affects all consumers big or small, rich or poor. It can also lead to a

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1. Personal detriment — negative outcomes for individual consumers, relative to reasonable expectations.
2. Structural detriment — the loss of consumer welfare (measured by consumer surplus) due to market failure or regulatory failure.

"An analysis of the issue of consumer detriment and the most appropriate methodologies to estimate it; Final report for DG SANCO by Europe Economics" (2006) Europe Economics.

[125] Sum of total post-redress financial detriment & monetised time loss. *"Study on measuring consumer detriment in the European Union"* (2016) Civic Consulting,

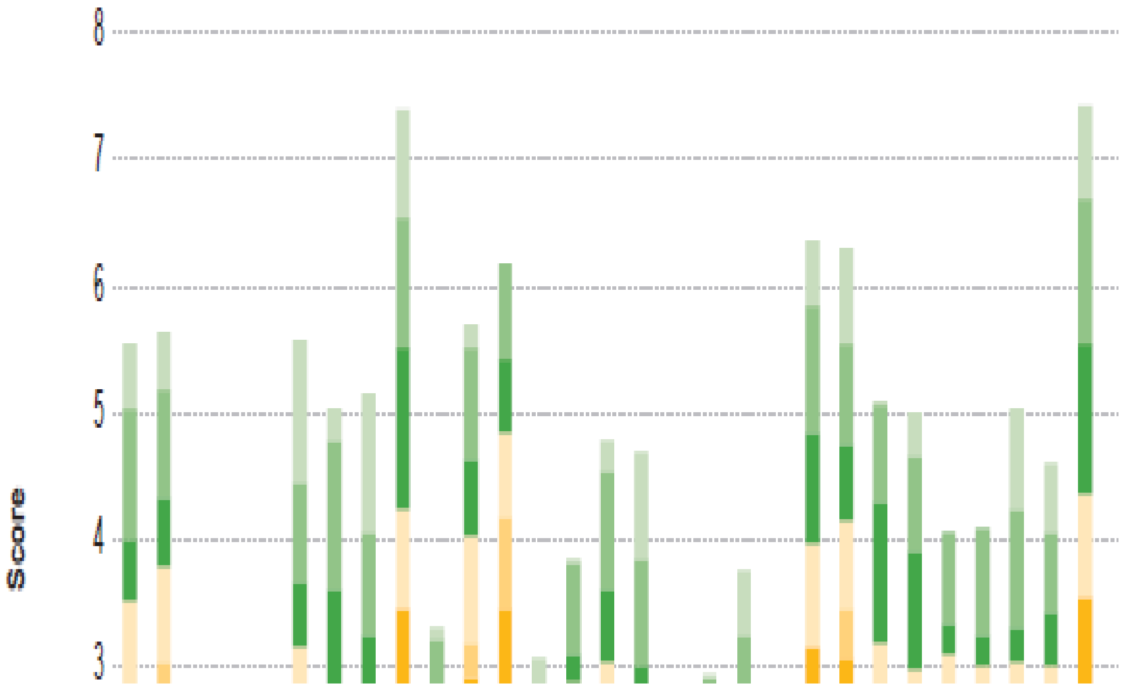
[126] This figure is comprised of Member States which regulate both electricity and gas prices, as well as Member States which regulate exclusively gas or electricity prices. In addition, Commission classifies Italy as having regulated electricity prices whereas ACER does not in their "*Market Monitoring report 2014*" (2015) ACER, http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015, pp 88-96,

[127] The indicator is measured as part of the Eurostat Survey on Income and Living Conditions (EU-SILC).

chicken-and-egg problem whereby price regulation leads to distortions to the market and low competition, which are in turn used to justify the continuation of price regulation. Resolving this impasse would allow one of the most fundamental aspects of the market – the price mechanism – to function properly.

ACER's Retail Competition Index – a composite indicator that draws upon many of the abovementioned statistics, as well as others[128] – was developed to achieve a full picture of retail market competitiveness which is not dependent on a single indicator. It illustrates the disparities in retail markets that still exist between Member States, and clearly suggests that competition can be improved in a number of them (see Graph 3).

Figure 6: ACER Retail Competition Index (ARCI) for electricity household markets in 2014



Source: ACER

2.4.2. Driver 2: Possible conflicts of interest between market actors that manage and handle data

High levels of information asymmetry (between incumbents and potential entrants) and high transaction costs impede competition and the provision of high levels of service on retail markets for energy.

[128] 1) Concentration ratio, CR3; 2) Number of suppliers with market share > 5%; 3) ability to compare prices easily; 4) average net entry (2012-2014); 5) switching rates (supplier + tariff switching) over 2010-2014; 6) non-switchers; 7) number of offers per supplier; 8) measure of whether the market meets consumer expectations; 9) average mark-up (2012–2014) adjusted for proportion of consumers on non-regulated prices.

For example, studies from NRAs cite discriminatory access to information on potential customers as a key barrier for new entrants to EU retail energy markets (Box 1 below). As most DSOs are also energy suppliers, safeguards are necessary to prevent them using privileged access to consumer data – especially smart metering data – to gain a competitive advantage in their supply operations.

In addition, "unjustified" or "incorrect" invoices are one of the largest sources of electricity and gas consumer complaints reported to the Commission[129] – an issue that can be largely resolved if accurate metering information were made quickly and readily available to suppliers and consumers.

Information technology could directly address these issues, making the market more contestable, facilitating the development of new services and improving the customer experience around day-to-day operations such as billing and switching. Although 80% of EU consumers should have smart meters by 2020, the experience from Member States that have already rolled them out indicates that robust rules are necessary to ensure the full benefits of smart metering data are realised, and that data privacy is respected. Such rules, however, are not fully developed in the existing EU legislation, and the diverse interests of market actors who may be involved in data handling mean that they are unlikely to emerge without regulatory intervention.

[129] These made up around 10% of all electricity and gas complaints. Source: *European Consumer Complaints Registration System.*

Box 1: Data management as a market entry barrier[130]

Data management comprises the processes by which data is sourced, validated, stored, protected and processed and by which it can be accessed by suppliers or customers

The necessity to adapt to different data management models for each market can have an impact on the resources of the potential market newcomers. Non-discriminatory and smooth accessibility of data is naturally most important during the pre-contractual phase as well as for running contractual situations. The fact that not all countries have rolled out smart meters yet also creates significant differences in the availability and accessibility of data.

A standardised approach to the provision and exchange of data creates a level playing field among stakeholders and helps to encourage new challenging market actors to enter a new market.

2.4.3. Driver 3: Low levels of consumer engagement

Consumer engagement is essential for the proper functioning of the market. As such, it is closely inter related with competition (Driver 1). However, consumers are also put-off from engaging in the market by behavioural biases and bounded rationality that make it harder for them to take the decision to search for, and to switch to, the best offer.

In particular, three key barriers to consumer engagement have been identified. First, the broad variety of fees that consumers may be charged when they switch diminishes the (perceived) financial gains of moving to a cheaper tariff in what is already a marginal decision for many consumers. The evidence suggests around 20% of electricity consumers in the EU currently face a fee of between EUR 5 and EUR 90 associated with switching suppliers. A portion of those fees – affecting around 4% of consumers – may be illegal under existing EU legislation (see Section 2.6.2).

Secondly, whereas online comparison websites play an important role in helping consumers to make an informed decision about switching suppliers, recent reports of unscrupulous practices have damaged consumer trust in them. Identified issues include the default presentation of deals by some websites, the use of misleading language, and a lack of transparency about commission arrangements. Indeed, a third of respondents to a recent EU survey somewhat or strongly agreed that they did not trust comparison websites because they were not impartial and independence.[131]

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130 Adapted from: *CEER Benchmarking report on removing barriers to entry for energy suppliers in EU retail energy markets*, (2016) p. 19, http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/tab6/C15-RMF-70-03_BR_barriers_to_entry_for_suppliers_1-Apr-2016.pdf. See also VaasaETT (2014), ' *Market Entrant Processes, Hurdles and Ideas for Change in the Nordic Energy Market*', p.22, http://www.nordicenergyregulators.org/wp-content/uploads/2014/12/VaasaETT-Report-Market_Entry_Barriers.pdf.

131 "*Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools*" (2013) European Commission, pp. xix, 191.

And thirdly, consumer groups report that consumers have difficulties understanding their energy bills and comparing offers in spite of existing EU legislation aiming to facilitate this. There is a broad divergence in national requirements around billing and consumer satisfaction with their bills varies significantly between different Member States. Whereas energy bills are the foremost means through which suppliers communicate with their customers, consumers' inability to correctly answer simple questions about their own electricity use reveals that bills are not effective in providing information that could facilitate effective consumer choice.[132] Addressing this will be increasingly important with the shift to more varied consumer products.

R&D results: The project S3C has developed a toolkit for the active engagement of end users and identifies improvements to the way and content of the communication of energy system actors with customers and citizens.

2.5. What is the EU dimension of the problem?

The EU's electricity market is strongly integrated physically, economically and from a regulatory point of view. The discretion of Member States to act individually has been substantially reduced by the resulting interdependencies and, in fact, can create significant externalities if not adequately framed within an EU-wide context.

RES E deployment is expected to increase in all Member States. The need to spur the emergence of a more flexible electricity system thus exists EU-wide. Moreover, as the EU electricity system is both physically and economically integrated, non-coordinated action is likely to increase the costs of RES E integration.

The same applies to CMs where the externalities of non-coordinated action are one of the underlying reasons for the proposed measures. It is true that not all Member States have enacted CMs, however the benefits of a more coordinated approach will benefit all Member States. Member States that have implemented a CM will be able to lower their costs by increased cross-border competition whereas the avoidance of negative spill-over effects will benefit all Member States regardless as to whether they enacted a CM or not.

In an integrated electricity market, considering the prevention and management of electricity crisis a purely national issue leads to serious problems. Where crisis situations occur, they often have a cross-border effect, and can entail serious adverse consequences for the EU as a whole. Evidence shows that non-coordinated approaches to preventing and managing electricity crisis may seriously distort the internal electricity market and put at risk the security of supply of neighbouring Member States.

Well designed and implemented consumer policies with a European dimension can enable consumers to make informed choices that reward them through healthy competition, and support the European goal of sustainable and resource-efficient growth, whilst taking account of the needs of all consumers. Increasing confidence and ensuring that unfair trading practices do not bring a competitive advantage will also have a

[132] For example, less than one third of consumers recently surveyed strongly agreed that they knew what kind of a contract they currently had (fixed price, variable price, green, etc.).

positive impact in terms of stimulating growth. The consumer-related measures undertaken as part of this initiative therefore play an essential role in the establishment and functioning of the internal market.

2.6. How would the problem evolve, all things being equal?

2.6.1. The projected development of the current regulatory framework

In the absence of additional measures, the electricity market would continue to be governed by the Third Package and the Electricity Security of Supply Directive. Various network codes may still be adopted and implemented[133], such as the draft Network Code on Emergency and Restoration and the Balancing Guideline. Whilst these network codes will help address some of the issues identified above, they will not offer a sufficient remedy on their own.

Solving the above-identified problems requires measures that cannot be addressed in the current legal framework. As the network codes constitute secondary implementing legislation designed to amend non-essential elements of the Third Package by supplementing it, their scope is confined to the same limits drawn by the Third Package and hence, developing new network codes cannot be expected to provide for adequate solutions either.

In view of the fact that the proposals in essence develop new areas for which currently no clear legal basis exist in the Third Package or in the Electricity Security of Supply Directive, stronger enforcement is not an option either (with some limited exceptions, which are further developed below).

Member States have developed forms of voluntary collaboration that attempt to address some of the problems identified. However, these initiatives cannot be expected to resolve all problems and with the same effectiveness as EU action (See also EU value added).

Regarding security of supply in particular, both the evaluation and the results of the public consultation clearly show that Directive 2009/89 is outdated. It does not take account of the current, fast evolving situation of the electricity market. And it offers no framework for coordinating national policies in the area of security of electricity supply.

With regards to consumer issues, the Commission may develop guidance to tackle implementation issues caused by difficulties in interpreting the existing legislation. In particular, it may issue an interpretative note on the existing provisions in the Electricity and Gas Directives covering switching-related fees, as well as further guidance on how the dozen or so consumer Directives relevant to comparison tools should be applied.

On energy poverty, the Commission will already set up the EU Energy Poverty Observatory using funds already secured from the European Parliament. However, the extent to which the Observatory continues to share good practices and improve data gathering is uncertain, as continued funding is not secured beyond the first year of

[133] For a full overview of network codes, see Annex VII.

operation. Moreover, the impact of this measure may be limited as the current legislation does not require Member States to measure energy poverty and hence to address it.

2.6.2. Expected evolution of the problems under the current regulatory framework

Both this and the impact assessment for the parallel RED II initiative come to the conclusion that the electricity market, provided that it is improved, together with projected CO2 prices, may deliver investments in most mature low-carbon technologies such as solar PV and onshore wind by 2030. However, in the absence of a market optimised for increasing levels of renewable penetration, achieving the 2030 objectives will only be possible at significantly higher costs.

In the absence of a better defined framework for government interventions, the current trend of non-coordinated implementation of national resource adequacy measures risks proliferating, undermining the efficiency of the market to deliver efficient production and investment decisions and defragmenting its regulatory framework.

In fact, in the absence of measures that will improve investment incentives and efficient market functioning, it is likely that more Member States will have to take recourse to means other than the market to secure sufficient investments for resource adequacy purposes, setting in motion a negative spiral in which government interventions increase the need for the subsequent one.

Failing to integrate all participants in the market means that their decisions will not be guided by market signals, entailing the risks that their investment and production decisions will be sub-optimal from a welfare perspective, if not distort markets.

In addition, in the absence of a clear framework for co-ordinated action between Member States when it comes to preventing and managing crisis situations, the EU's electricity system risks being increasingly exposed to risks of serious incidents, without the EU or its Member States having any means to properly tackle them. There is a real risk that Member States will continue to do as they see fit in crisis situations, thus undermining the proper functioning of the internal electricity market.

Regarding active consumer engagement, Member States have committed to deploying smart meters to around two thirds of the population while access to innovative services such as demand response or in the area of self generation remains limited in many Member States. Individual action by Member States would perpetuate current differences in the Union regarding consumer awareness, choice and access to dynamic prices, demand response and integrated smart services. Consumer-friendly functionalities would be taken up partially and the flexibility consumers can provide to the electricty system would remain largely untapped.

With regards to consumer protection and engagement, enforcement could help diminish the illegal switching-related costs currently faced by an estimated 4% of all EU electricity consumers. And some Member States may also voluntarily cease or reduce excessive regulatory interventions in price-setting as their retail markets mature. However, shortcomings in the existing legislation will greatly limit the Commission's ability to tackle these and other consumer-related problem drivers more effectively.

The issue of energy poverty is likely to remain relevant. Pressure on energy prices may continue as a result of the efforts to decarbonise the energy system. If energy prices grow faster than household income, more and more households will find it difficult to pay their energy bills. This may have a knock-on effect on Member States willingness to lift price regulation which will ultimately impact suppliers' ability to innovate, competition and consumer welfare. Thus, the greater the importance of enhanced transparency to estimate the number of energy poor households.

And whilst many Member States may seek to ensure the neutral, expedient, and secure management of consumer data, it is highly likely that national requirements will vary significantly, leading to an uneven playing field for new suppliers and energy service companies in the EU. Here, the only credible approach to effectively tackling the potential conflicts of interest among market actors is a legislative one.

2.7. Issues identified in the evaluation of the Third Package

A retrospective evaluation was carried out in parallel with the present impact assessment and has been added as Annex VI. Its main conclusions are:

- That the initiative of the Third Package to further increase competition and to remove obstacles to cross-border competition in electricity markets has generally been effective and that active enforcement of the legislation has led to positive results for electricity markets and consumers. Markets are in general less concentrated and more integrated than in 2009. As regards retail markets, the set of new consumer rights introduced by the Third Energy Package have clearly improved the position of consumer in energy markets.
- However, the success of the rules of the Third Package in developing the internal electricity market further to the benefit of customers remains limited in a number of fields concerning wholesale and retail electricity markets.
- Moreover, while the principles of the Third Package achieved its main purposes (e.g. more supplier competition), new developments in electricity markets such as the increase of RES E, the increase of state interventions into the electricity markets and the changes taking place on the technological side have led to significant changes in the market functioning in the last five years and have dampened the positive effect of the reforms for customers. There is a gap in the existing legislation regarding how to deal with these developments.

The conclusions of the evalution are also reflected in section 3 of each of the Annexes 1.1 throught to 7.6 to the present impact assessment.

3. SUBSIDIARITY

3.1. The EU's right to act

In order to create an internal energy market, the EU has adopted three consecutive packages of measures between 1996 and 2009 aiming at the integration and liberalisation of the national electricity and gas markets and addressing a wide range of elements such as market access, the improvement of the level playing field, transparency, increased rights for consumers, stronger independence of regulatory authorities, etc. In February 2011, the European Council set the objective of completing the internal energy market by 2014 and of developing interconnections to put an end to any isolation of Member States from the European gas and electricity grids by 2015. In June 2016, the European Council called for Single Market strategies, including on energy, and action plans to be proposed by the Commission and to be completed and implemented by 2018.

Article 194 of the Treaty on the Functioning of the European Union ('**TFEU**') consolidated and clarified the competences of the EU in the field of energy. According to Article 194 TFEU, the main aims of the EU's energy policy are to: ensure the functioning of the energy market; ensure security of energy supply in the Union; promote energy efficiency and energy saving and the development of new and renewable forms of energy; and promote the interconnection of energy networks.

The planned measures of the present intiative further progress towards the objective of improving the conditions for competition by improving the level playing field, while at the same time adjusting to the decarbonisation targets and enhancing the solidarity between Member States in relation to security of supply.

Therefore, Article 194 TFEU is the legal basis of the current proposal.

3.2. Why could Member States not achieve the objectives of the proposed action sufficiently by themselves?

The section below provides a high-level summary of the necessity of EU action, based on the four problem areas identified in section 2.

The issue of subsidiarity is also discussed in section 6 of Annexes 1.1 to 7.6 to the present impact assessment.

As regards the issue concerning a market design that is not fit for taking up large amounts of variable, decentralised electricity generation and allowing for new technical developments, it is important to note that EU action is necessary to ensure that national markets are comparable in order to improve the functioning of the internal electricity market and enable maximum cross-border trading to happen. EU-action is also necessary in order to enhance the transparency in the functioning of the electricity markets and avoid discrimination between market parties. Moreover, a number of the measures proposed to address this issue (e.g., measures for the common sizing and procurement of balancing reserves) require full cooperation of neighbouring TSOs and NRAs, and hence individual Member States might not be able to deliver a workable system or might only provide suboptimal solutions. Moreover, existing provisions under the Third Package are arguably not sufficiently clear and robust and their implementation of such rules has highlighted areas with room for improvement and hence EU action will be necessary to address the identified shortcomings.

With specific respect to DSOs, distribution grids will have to integrate even greater amounts of RES E generation in the future, and so ensuring all DSOs can efficiently manage their networks will help to reduce distribution costs and thereby support the achievement of EU RES targets. In addition, widely divergent distribution tariff regimes may affect the development of the internal energy market as they affect the conditions under which RES E generation or other resources can access the grid and participate in the national and cross-border energy markets. EU action in these areas would thereby facilitate the deployment of RES E and create a level playing field for flexibility services such as demand response by ensuring a coherent approach by Member States based on common principles. Developing this through independent Member State action would not be feasible given the heterogeneity of current national networks and regulations.

Concerning the uncertainty about future investments in generation capacity and uncoordinated government interventions, the measures in the proposed initiative aim at improving the functioning of the electricity markets and at improving the coordination between Member States for capacity mechanisms. The necessity of EU action derives from the fact that as regards the measures for improving the functioning of the electricity markets, these are already covered by EU legislation, although not sufficiently clearly, and therefore an amendment to such measures to address the distortions and deficiencies identified would require EU action. For the measures concerning the improvement of the coordination between Member States for capacity mechanisms, given that the aim is to address the shortcomings identified from resource adequacy assessments carried out at national level and to develop the cross-border participation in capacity mechanisms, the EU is best placed to provide for a harmonised framework.

In relation to the problem that Member States do not take into account of what happens across their borders when preparing for and managing electricity crisis situations, the necessity of EU action is based on the evidence that uncoordinated national approaches not only lead to the adoption of suboptimal measures but that they also make the impacts of a crisis more accute. Given the interdependency between the electricity systems of Member States, the risk of a blackout is not confined to national boundaries and could directly or indirectly affect several Member States. Therefore, the actions concerning preparedness and mitigation of crisis situations cannot be defined only nationally, given the potential impact on the level of security of supply of a neighboring Member State and/or on the availability of measures to tackle scarcity situations.

Regarding the slow deployment of new services, low quality of services and increasing mark-ups on retail markets, there is a clear need for EU action to ensure convergence of national rules, which is a precondition for the development of cross-border activity in the retail markets. Moreover, national regulations have in some instances led to distortions, weakening the internal energy market. Such distortions can be observed in relation to the protection of vulnerable and energy poor consumers which is a policy area characterised by a great variety in types of public internvention across Member States, both in terms of the definitions used and in terms of the levels of protection established. In that case EU action is justified not only to ensure customer protection and enhanced transparency but also to improve the functioning of the internal market through a more cohesive approach across all markets.

3.3. Added-value of action at EU-level

The initiative aims at amending existing EU legislation and at creating new frameworks for cross-border cooperation, which can legally and practically only be achieved at the European level.

National policy interventions in the electricity sector have direct impact on neighbouring Member States. This even more than in the past as the increasing cross-border trade, the spread of decentralised generation and more enhanced consumer participation increases spill-over effects. No state can effectively act alone and the externalities of unilateral action have become more important.

To illustrate, uncoordinated national policies for distribution tariffs may distort the internal market for distributed resources such as distributed generation or storage, as such resources will increasingly participate in energy markets and provide ancillary services to the system, including across borders. Furthermore, the lack of appropriate incentives for DSOs may slow down the integration of RES E, and the uptake of innovative technologies and energy services. EU action therefore has significant added value by ensuring a coherent approach in all Member States.

It is true that certain Member States collaborate on a voluntarily basis in order to address certain of the identified problems (e.g. Pentalateral Energy Forum –PLEF-, CEEE). However, these fora are characterised by different levels of ambition and effectiveness and are held-back by the fact that no means exist to enforce agreements on market design related arrangements. Moreover, even if one would presume that they would be fully effective in these regards, they geographically cover only part of the EU electricity market.

It should be added that clear synergies exist between the present initiative and other EU policy objectives, notably the EU's climate policies and other policy objectives in the energy field. Indeed, a well-functioning market is the base upon which the ETS can most efficiently deliver its goals and will permit a cost effective integration of RES E in the EU's electricity markets.

Consequently, the objectives of this initiative cannot be achieved only by Member States themselves and this is where action at EU-level provides an added value.

4. OBJECTIVES

4.1. Objectives and sub-objectives of the present initiative

GENERAL POLICY OBJECTIVE:
Making electricity markets more secure, efficient, competitive, whilst ensuring that electricity is generated in a sustainable way, and remains affordable to all.

OBJECTIVE:
Adapt market design for the cost effective operation of variable, decentralized generation, taking into account technological developments.

SUB-OBJECTIVES:
- Removing current market distortions between different ways of generating electricity;
- Make the market more flexible and adapt it for the cost-effective operation of RES E;
- Improve market participation and incite technological change.

OBJECTIVE:
Facilitate investments in the right amount and type of resources to ensure security of supply, whilst limiting the distortive effects of uncoordinated capacity mechanisms.

SUB-OBJECTIVES:
- Strengthen price formation and improve market functioning to reduce the need for state-intervention;
- Make state-interventions for future generation capacities more efficient and compatible with the Internal electricity market.

OBJECTIVE:
Improve Member States' reliance on each other in times of system stress and reinforce their coordination and cooperation at times of crisis situations.

SUB-OBJECTIVES:
- Improving risk assessment and preparedness;
- Improving transparency and information sharing;
- Improving coordination in emergency.

OBJECTIVE:
Address the causes and symptoms of weak competition on energy retail markets.

SUB-OBJECTIVES:
- Decreasing government intervention in retail price setting;
- Reducing information asymmetry between market actors and transaction costs around data management;
- Removing barriers to switching and improving the comparability of offers in the market;
- Enabling consumers to take full advantage of market opportunities by actively managing consumption and self-generated electricity;
- Protecting energy poor and vulnerable consumers in a more targeted and less distortive manner.

4.2. Consistency of objectives with other EU policies

The consistency of the present initiative with various parallel initiatives in the energy policy area was already explored in section 1.2.

The **ETS** constitutes a cornerstone of the European Union's policy to combat climate change and its key tool for reducing industrial and electricity sector greenhouse gas emissions cost-effectively. To achieve the at least 40% greenhouse gas emission reduction target, the sectors covered by the ETS, which includes electricity generation, have to reduce their emissions by 43% compared to 2005. The ETS interacts with the electricity markets as it places a price on emissions of CO2, which is proportional to the emissions' intensity of electricity production. This can be taken into account for both operational decisions as well as for investment decisions, in which price expectations for the future will also play a larger role due to the long-term nature of investments in the electricity sector. (By contrast, decommissioning decisions may be primarily driven by short-term considerations relating primarily to operational costs and revenues). The ETS thus functions by affecting production and investment decision of electricity market actors[134]. It follows that an ETS can only function if its is complemented by an efficient electricity market is. The objectives of the ETS and the present proposals are hence complementary to one another and mutually reinforcing.

The **Effort Sharing Decision** establishes binding annual greenhouse gas emissions for Member States for the period 2013-2020 in sectors not covered by the ETS and forms part of the climate and energy package. As part of the 2030 climate and energy framework, a similar binding emission reduction framework is proposed for the period 2021-2030. Reducing greenhouse gas emissions by 30% in effort sharing sectors below 2005 levels can have an indirect impact on the projection for the demand of electricity in 2030 and this has been taken into account in the Impact Assessment by using the EUCO27 scenario in the baseline against which the impacts of the present initiative is being assessed.

The **Communication on the decarbonisation of transport in 2030** aims at setting out a strategy covering several legislative and non-regulatory initiatives covering the transport sector which will be subsequently proposed to contribute to meeting the agreed 2030 greenhouse gas reduction targets. The decarbonisation of transport in 2030 has an impact on the projection for the demand of electricity in 2030, primarily via the electrification of transport, and this has been taken into account in the Impact Assessment by using the EUCO27 scenario in the baseline against which the impacts of the present initiative is being assessed. The efficient integration of electric vehicles into the electricity system

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[134] The existing imbalance between the supply and demand for ETS allowances has limited the impact of the carbon price in recent years. However, the agreement in 2014 to postpone the auctioning of 900 million allowances, and the decision in 2015 to introduce a Market Stability Reserve from 2019 onwards, as well as the proposal to revise the EU ETS, including a higher annual reduction to the number of allowances in the ETS from 2021 onwards, will gradually address the surplus of allowances. With the introduction of the auctioning of allowances as the default method of allocation for installations in the power sector from 2013 onwards and a single EU wide limit or cap on the overall number of allowances in the system, the EU ETS already provides a largely harmonised incentive for decarbonisation at EU level.

requires incentivising their charging to take place at times of low electricity demand and/or high supply. The present initiative aims at enabling and rewarding consumers to manage their consumption, including when charging their electric vehicles, actively via demand response thus enabling smart charging. In essence, electric vehicles will thus become part of the supply of flexibility to the electricity system.

EU's competition instruments and, in particular, the EU state aid rules are applicable to the energy sector. They have been clarified in the **Guidelines on State aid for environmental protection and energy 2014-2020**[135]. These EEAG aim at supporting Member States in reaching their 2020 targets while addressing the market distortions that may result from subsidies granted to RES. To this end, the EEAG promote a gradual move to market-based support for RES E. They also include provisions on aid to energy infrastructure and rules on aid to secure adequate electricity capacity, allowing Member States to introduce CMs when there is a real risk of insufficient electricity generation capacity. The objectives and the rules of the EEAG are set to avoid undue competition distortions from national support provided in the energy sector. The proposed initiative to strenghten efficient, integrated and functioning electricity markets is complementary to this framework.

The existing EEAG already go a considerable way in guiding CMs. The present initiaitve intends to complement this framework. For instance:

- The EEAG require that state intervention in support of resource adequacy must be necessary. The MDI impact assessment[136] thus explores options for creating a robust framework for assessing the EU's adequacy situation which could give a good sense how much intermittent renewables can contribute to security of supply or to what extent Member States can rely on supplies from their neighbours. Today, Member States introduce capacity mechanisms based on national reports which assess these factors very differently and underestimate the contribution of RES E or foreign supplies to a Member States' security of supply. Therefore a genuine and high quality assessment which will help assessing real needs and question unfounded national claims.
- The EEAG already require that national capacity markets are open to foreign resources. However, organising effective foreign participation in national mechanism requires active contributions of several parties. The MDI impact assessment[137] explores options for defining clear roles and responsibilities to capacity providers, transmission system operators and regulators so that foreign participation becomes effective and that investment incentives are not distorted across the borders.

The proposed changes on the new performance based remuneration framework for DSOs would also support the **Digital Single Market Strategy** in the sense that those would provide further incentives to enable cross sector synergies in electronic communication infrastructure deployment allowing win win solutions for the cost efficient and timely

[135] http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52014XC0628(01)
[136] See the preferred option in problem area II
[137] See the preferred option in problem area II

smartening of grids and high speed connectivity for EU citizens, also decreasing the digital divide and providing the backbone for digital products and services which have the potential to support all aspects of the lives of EU citizens, and drive Europe's economic recovery. The proposed measures would complement from the energy regulatory side the measures already introduced with Directive 2014/61/EU which aims at reducing the cost of high speed broadband infrastructure deployment partly via cross sector synergies.

The proposed measures do in general have no interaction with the fundamental rights laid down in the **Charter of Fundamental Rights**, with the exception of the processing of personal data and improvement of consumer protection. These elements are discussed in more detail in section 6.4.6, Annex 7.1 and Annex 7.3.

The New Skills Agenda for Europe focuses on skills as an elevator to people's employability and prosperity, in line with the objective of a "social triple-A" for Europe. It will promote life-long investment in people, from vocational training and higher education through to digital and high-tech expertise and the life skills needed for citizens' active engagement in changing workplaces and societies. The energy transition will bring significant shifts in employment and skill sets required for employees active in the energy sector as traditional means of generation will be replaced by RES E. This transition is however primarily driven by EE and RED II related measures as well as national choices as to the generation mix. More relevant for the present initiative are the measures aiming at inducing the development of the retail markets from electricity supply markets towards including more service oriented product offerings facilitating the participation of consumers in the electricity market.

As regards **consumer rights**, the Unfair Commercial Practices Directive is the overarching piece of EU legislation regulating unfair commercial practices in business-to-consumer transactions. It applies to all commercial practices that occur before (i.e. during advertising or marketing), during and after a business-to-consumer transaction has taken place. Where sector-specific EU law is in place and its provisions overlap with the provisions of the UCPD, the corresponding provisions of the sector-specific EU rules prevail, so no contradictions exist.

Research, Innovation and Competitiveness being Energy Union's 5th dimension**,** cuts across all its elements. The Strategic Energy Technology Plan implements the energy union's fifth dimension, promotes research and innovation for low carbon technologies, contributing to the transformation of the EU's energy system and creating jobs, growth and global export opportunities in the fast-growing clean-technology sector. Technological developments create opportunities for citizens to turn from being passive consumers of electricity into prosumers that actively manage their consumption, storage and production of electricity and participate in the market and allow for the increasing penetration of distributed resources. A new Research, Innovation and competitiveness strategy, encompassing energy, transport and industrial competitiveness aspects is expected to be presented in the months to come. This strategy builds on the achievements of the SET Plan and further addresses the R&I challenges particularly towards industrialisation of innovative low carbon technologies.

The present initiative is fully coherent as it seeks to remove barriers for the participation of consumers, for bringing new resources to the market and seeks to improve price formation with a view to create the conditions for new business models to emerge and for innovative products to be absorbed by the market.

5. POLICY OPTIONS

A fully functioning European wide electricity market is the best means to ensure that electricity can be delivered to consumers in the most cost-efficient way at any time. To continue fulfilling that purpose, the electricity market needs to be able to adapt to the significant increase of variable renewable electricity production, integrate new enabling technologies such as smart grids, smart metering, smart-home, self-generation and storage equipment, empower citizens to take ownership of the energy transition and assure security of electricity supply at least costs. Market mechanisms may need to be complemented by initiatives which help preventing and managing electricity crisis situations.

Any EU action aimed at strengthening the market should build on the gradual liberalisation of the EU energy markets resulting from the three Energy Packages described earlier in this document.

The following policy options have been considered to address the problems of today's electricity market and to meet the broad energy policy objective of ensuring low carbon electricity supply to European customers at least costs. In assessing all possible options to achieve this broad objective, the following approach was taken:

- Identification of the main areas where initiatives might be needed to achieve the main objectives of a new electricity market design. These Problem Areas are set out in Box 2 below: "Overview of Problem Areas".
- To address each Problem Area a set of high level options was identified (set-out in the following paragraphs). Each of these high level options groups options for specific measures.
- A bottom-up assessment was performed for each specific measure, comparing a number of options in order to select the preferred approach. The assessments of the specific measures can be found in the Annexes to the present impact assessment.

To help the reader, a table matching the assumed measures for each high level option is included at the end of each problem area with references to the Annexes.

Box 2: Overview of Problem Areas

Problem Area I:	Market design not fit for taking up large amounts of variable, decentralised electricity generation and allowing for new technological developments
Problem Area II:	Uncertainty about sufficient future investments in generation capacity and un-coordinated government interventions
Problem Area III:	Member States do not take sufficient account of what happens across their borders when preparing for and managing electricity crisis situations
Problem Area IV:	The slow deployment of new services, low levels of service and poor retail market performance

5.1. Options to address Problem Area I (Market design not fit for an increasing share of variable decentralized generation and technological developments)

5.1.1. Overview of the policy options

With a significant part of the produced electricity coming from variable renewable sources and distributed resources, new challenges will be arising in terms of security of supply and electricity price volatility. The options examined here aim to address these challenges in the most cost-effective way for the whole European electricity system. These system cost savings will be passed on to consumers by way of lower network charges. They will also make it easier for RES E assets to earn a higher fraction of its revenues through the market.

Two possible paths were identified: the path of enhancing current market rules in order to increase the flexibility of the system, retaining to a certain extent the national operation of the systems (with more or less coordination assumed depending on the related sub-options) and the path of moving to a fully integrated approach.

Box 3: Overview of the Policy Options for Problem Area I

Each policy option consists of a package of measures which address the drivers of the problem. In the following sub-sections, the high level policy options and the packages of measures they contain are described. Details on the individual measures are included in the Annexes. It is then explained if any of those options are to be discarded at this stage, prior to assessment, or whether other options were considered but were discarded from the outset. The section is closed by a table summarising all specific measures included in each option and references to the Annexes where each measure is described and asessed in more detail.

The relevant Annexes addressing the policy options below in more detail are: 1.1 to 3.4.

5.1.2. Option 0: Baseline Scenario – Current Market Arrangements

Under this option no new legislation is adopted, but there is some effort to implement existing legislation including via the adoption of so-called network codes or guidelines. The network codes, provided for in Article 6 and the guidelines provided for in Article 18 of the Electricity Regulation specify technical rules on the operation of European electricty markets[138]. They are, as such, only designed to amend non-essential elements of the Electricity Regulation and can only be adopted in areas specifically mentioned in the above mentioned Articles.[139]

Under these limitiations, network codes/guidelines are not the suitable instrument to achieve all objectives of this initiative. For instance, whereas the implementation of the Guideline on Capacity Allocation and Congestion Management ('CACM Guideline') will bring a certain degree of harmonisation of cross-border intraday markets, gate closure times and products for the intraday, as well as a market clearing, there is no guarantee that the local market will adapt to reflect the cross-border approach and practices (auctions / continuous trading) and local intraday markets across Europe will continue to remain non-harmonised. This means that the EU-wide intraday market coupling envisaged by the CACM Guideline will not be able to reach its full potential.

The Balancing Guideline is expected to bring certain improvements to the balancing market, namely the common merit order list for activation of balancing energy, the standardisation of balancing products and the harmonisation of the pricing methodology for balancing. Nonetheless, other important areas like balancing capacity procurement rules, frequency, geographical scope and sizing will not be affected by this regulation.

Priority dispatch rules, must-run priorities and other technology specific rules related to the scheduling and operation of the system do not change at all with the adoption of network codes. The same applies for the possibility for demand and distributed resources to access the markets, and to compete on a level playing field with thermal generation. The baseline assumes that demand response exists only in countries where it currently has access to the market, with only industrial consumers being able to participate.

Overall, this option assumes that the future situation will remain more or less the same as today, except from some specific measures included in the network codes (as above). The

[138] More detail as regards network codes and guidelines is provided in Annex VII.
[139] CIGRE paper C5-202 (2016): "*Market coupling, facing a glorious past?*" by R.Hirvonen, A.Marien, B.Den Ouden, K.Purchala, M.Supponen, describes the past and future challenges of implementing market coupling.

baseline does not consider explicitly any type of existing support schemes for power generation plants, neither in the form of RES E subsidies nor in the form of CMs[140].

Stakeholders' opinions[141]: None of the respondents to the public consultation expressed the opinion that there is no need for further upgrade of the current market arrangements.[142]

5.1.3. Option 0+: Non-regulatory approach

Whilst systematically considered[143], no such option could be identified[144].

Stronger enforcement provides little scope for improving the level playing field among resources. To the extent the lack of a level playing field is due to the variety of provisions in national law, a clear and transparent EU framework is a prerequisite for any improvement. If the lack of a level playing field is due to exemptions in the EU regulatory framework, stronger enforcement of these would actually be counter productive. In this regard, the Evaluation report indicates that the rules of the Third Energy Package appear to be insufficient to cope with the challenges facing the European electricity system.[145]

Moreover, voluntary cooperation has resulted in significant developments in the market and a lot of benefits. However, it it unlikely to provide for appropriate levels of harmonisation or certainty to the market and legislation is needed in this area to address the issues in a consistent way.

The current EU regulatory framework contains very limited rules on balancing and intraday markets in a manner that allow to strengthening these short-term markets. In particular, the Third Package does not address regional sizing and procurement of

[140] More details on the baseline and the reasons for not considering existing support schemes can be found in Annex IV.

[141] Stakeholders' opinions are reflected through-out Section 5 (and occasionally Section 6) of the main text of this impact assessment to provide insides into their views as to the various options considered. Stakeholder views are moreover reflected in detail in Section 7 of of each of the Annexes 1.1 throught to 7.6 to the present impact assessment.

[142] Some stakeholders propose to preserve only particular rules of the current market arrangements, while being supportive to other Commission proposals for upgrading of the electricity market. E.g., one stakeholder is supportive to more aligned framework for balancing markets and European measures to incentivise demand side flexibility and in the same time supports the priority dispatch and priority access for renewables. Similarly, one stakeholder strongly supports measures to incentivise the demand side response and strengthening the powers of ACER, but considers that power exchanges should not be subject to governance rules as well as that redesigning of the balancing markets is the task of Member States and not the EU.

[143] For each measure the opportunities for stronger enforcement have also been assessed in the annexes with measures associated with each option. References to the relevant annexes are provided in Sections 5.1.7, 5.2.9, 5.3.8 and 5.4.6

[144] The Commission has conducted – and is still conducting – a systematic *ex-officio* compliance check of national legislation with the Third Energy Package. While EU-Pilot or formal infringement procedures are still ongoing, they will however not be able to fulfil the policy objectives of the proposed measures.

[145] See Section 7.3.1., 7.34 and 7.3.4 of the Evaluation.

balancing reserves nor contain rules allowing achieving a larger degree of harmonisation of intraday trading arrangements.

Given that the existence of Regional Security Coordinators ('RSCs') depends on the implementation of the System Operation Guideline, RSCs may only be fully operational around mid-2019. Hence, stronger enforcement is currently not a possible option. Any progress beyond the framework in the System Operation Guideline and the application of other network codes would depend on the voluntary initiatives of TSOs. However, these voluntary initiatives would be limited due to constraints deriving from differing national legal frameworks.

As to demand response, stronger enforcement of existing provisions in the electricity and energy efficiency directives are unlikely to untap the potential of flexibility. This is because the existing provisions give Member States a high degree of freedom that has proven not to be specific enough to ensure a full removal of existing market barriers.

Evidence suggests that voluntary cooperation will not result in progress in this area, as there has been to date already significant opportunity to effect the necessary changes voluntarily.

In the case of DSOs the current EU regulatory framework does not provide a clear set of rules when it comes to additional tools that DSOs can employ to improve their efficiency in terms of costs and quality of service provided to system users. Moreover, the current framework does not address the role of DSOs in activities which are expected to have a key impact in the development of the market (e.g. data management).

5.1.4. Option 1: EU Regulatory action to enhance market flexibility

Electricity production from wind and sun is more variable and less predictable than electricity production from conventional sources of energy. Due to this, there will be times when renewables cover a very large share of electricity demand and times when they only cover a minor share of it. The large scale integration of such variable electricity production thus requires a more flexible electricity system, one which matches the variable production.

Options to deliver the desired flexibility may comprise:

a. Abolishing (i) those measures that enhance the inflexibility of the current system, namely priority dispatch for certain technologies (e.g. RES E, CHP, indigenous fuels) and "must-runs" of conventional generation, (**Creating a level playing field**) and (ii) barriers preventing demand response from participating in the energy and reserve markets;
b. In addition to the measures under a), better integrating short-term markets, harmonizing their gate closure times and bringing them closer to real-time, in order to take advantage of the diversity of generation resources and demand across the EU and to improve the estimation and signalling of actual flexibility needs (**Strengthening the short-term markets)**;

c. In addition to the measures under a) and b), **pulling all flexible distributed resources** concerning generation, demand and storage, **into the market** via proper incentives and a market framework better adapted to them, based on active aggregators, roll-out of smart-metering and time-of-use supply tariffs linked to the wholesale prices.[146]

The sub-options described above reflect a different degree of ambition to change the market, as well as the different views expressed among stakeholders on how strong the proposed interventions should be. Sub-option 1(a) (level playing field) retains a more national status of the markets, Sub-option 1(b) (strengthening short-term markets) moves also to more regionally coordinated markets, while Sub-option 1(c) (demand response/distributed resources) makes an additional step towards a more decentralised electricity market and system.

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[146] IEA "*Re-powering markets*" (2016) suggests: *... "dispatching" demand response as a generator requires complex market rules. Demand response can only be assessed according to a baseline consumption levels, which are difficult to define and can lead to hidden subsidies. Setting the right level of remuneration for aggregators has proven to be complex. Instead, dynamic pricing should be encouraged, using new measurement and automation technologies such as smart meters.*

European Parliament: *"…[I]n order to achieve the climate and energy targets, the energy system of the future will need more flexibility, which requires investment in all four flexibility solutions – flexible production, network development, demand flexibility and storage"*[.][147]

European Economic and Social Committee: *"The goal of a low-carbon energy supply, with a high proportion of adjustable renewable energy sources, can only be achieved in the short to medium term if all market participants (including new ones) have at their disposal enough options that afford flexibility, such as sufficient storage capacity, flexible, consumer-friendly demand options and flexible power generation technologies (e.g. cogeneration), as well as adequately upgraded and interconnected power distribution infrastructure. Other conditions are that consumers must receive adequate, timely and correct information, they must have the chance to develop their own marketing opportunities and the necessary investments in technology and infrastructure should pay off. None of this is currently the case"*[148].

Stakeholders' opinions: In the public consultation on Market Design Initiative most stakeholders supported full integration of renewable energy sources into the market e.g. through full balancing obligation and phasing-out priority dispatch. Also, most stakeholders agree with the need to speed up the development of integrated short-term, balancing and intraday, markets.

5.1.4.1.Sub-option 1(a): Level playing field amongst participants and resources

The first group of measures aims at removing market distortions resulting from manifold different regulatory rules for generation from different sources. Creating a level playing field among all generation modes and restoring the economic merit order curve is an important prerequisite for a well-functioning electricity market with prices that reflect properly actual demand and supply conditions. For this reason the measures described here are an integral part of all sub-options under Option 1.

The measures considered under this option would mainly target the removal of existing market distortions and create a level playing field among technologies and resources. This could involve abolishing rules that artificially limit or favour the access of certain technologies to the electricity market (such as so-called "must-run" provisions, rules on priority dispatch and access and any other rules discriminating between resources[149]). Industrial consumers would become active in the wholesale markets, both for energy and reserves, in all Member States. All market participants would become balance responsible, bearing financial responsibility for the imbalances caused and thus being

[147] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, Recital C.

[148] Opinion of the European Economic and Social Committee on the *´Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions – Launching the public consultation process on a new energy market design´*(COM (2015) 340 final) (2016/C 082/03), OJ C 82, 3.3.2016, p. 13-21, § 1.4. http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.C_.2016.082.01.0013.01.ENG&toc=OJ:C:2016:082:TOC

[149] See in detail Annex 1(1) – 1.

incentivized to reduce the risk of such imbalances. Dispatch and redispatch decisions would be based on using the most efficient resources available, curtailment should be a measure of last resort which is limited to situations in which no market-based resources are available (including storage and demand response), and only subject to transparent rules.

Therefore, all resources would be remunerated in the market on equal terms. This would not mean that all resources earn the same revenues, but that different resources face the same prices for equal services. In most cases the TSO should follow the merit order, allowing the market to define the dispatch of available resources, using the inherent flexibility of resources to the maximum potential (e.g. by significantly reducing must-run generation, creating incentives for the use of heat storage combined with CHP and the use of biomass generation in periods of peak demand rather than as baseload, and using demand response or storage where it is more efficient than generation). Where resources are used on the basis of merit order (thus on the basis of the marginal cost for using a particular resource at a given point in time)[150], supply costs are reduced.

Imposing additional obligations increases the risk and hence the financing costs of some technologies such as RES E. Part of this risk will be hedged through the more liquid intraday and balancing markets resulting from the full implementation of the Network Codes, in combination with the increased participation of resources due to the removal of must-run and priority dispatch provisions. These obligations should be also accompanied by measures that reduce their costs of compliance, such as the introduction of transparent curtailment rules. Additionally, exemptions from certain regulatory provisions may, in some cases, be required. This can e.g. be the case for emerging technologies, which, although they are not yet competitive, need to reach a minimum number of running hours to gather experience. For certain generators, particularly small RES E (e.g. rooftop solar), exemptions can be furthermore justified to avoid excessive administrative efforts related to being active on the wholesale markets.

Stakeholders' opinions:[151] Most stakeholders support the full integration of all technologies into the market, e.g. through full balancing obligations for all technologies, phasing-out priority dispatch and removing subsidies during negative price periods.

150 Where marginal costs are based on the use of fuel, this can also result in lower CO2 emissions. However, inflexible conventional plants will include the cost of starting or stopping power generation into their market bids, thus possibly deciding to operate at a price below their fuel costs. In this case, the cost of not operating the power plant exceeds the cost of operating it.

151 More detailed depictions of stakeholder's opinions are provided in Sections 7 of each annexe describing the more detailed measures i.e. annexes 1.1 to 7.6 of the Annexes to the Impact Assessment.

Also stakeholders from the renewable sector often recognize the need to review the priority dispatch framework. However, in their view, a phase-out of priority dispatch for renewable energy sources should only be considered if (i) this is done also for all other forms of power generation, (ii) liquid intraday markets with gate closure near real-time exist, (iii) balancing markets allow for a competitive participation of wind producers; (short gate closure time, separate up/downwards products, etc.), and (iv) curtailment rules and congestion management are transparent to all market parties.

Cogeneration sector stakeholder seek for a least parity between CHP and RES E.

European Parliament: *"European Parliament […]stresses that a new market design for electricity as part of an increasingly decentralised energy system must be based on market principles, which would stimulate investment, ensure that SMEs have access to the energy market and unlock a sustainable and efficient electricity supply through a stable, integrated and smart energy system[...]"*[152]

"European Parliament […] [i]nsists that, with the increasing technical maturity and widespread use of renewable energy sources, subsidy rules must be geared to market conditions, such as feed-in premiums, in order to keep costs for energy consumers within reasonable bounds[.]"[153]
"European Parliament […] recalls the existing provisions of the Renewable Energy Directive, which grant priority access and dispatch for renewables; suggests that these provisions should be evaluated and revised once a redesigned electricity market has been implemented which ensures a more level playing field and takes greater account of the characteristics of renewable energy generation[.]"[154]

Council: *"[…] Renewable energy sources should become an integrated part of the electricity market by ensuring a level playing field for all market participants and enabling renewable energy producers to be fully involved in the market, including in balancing their portfolio and reacting to market price signals."*[155]

European Electricity Regulatory Forum, Florence: *"The Forum stresses that the renewables framework for the post 2020 period should be based on an enhanced market design, fit for the full integration of renewables, a strong carbon price signal through a strengthened ETS, and specific support for renewables, that when and if needed, should be market based and minimise market distortions. To this end, the Forum encourages the Commission to develop common rules on support schemes as a part of the revision of the*

[152] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, §5.
[153] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, §52.
[154] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, §54.
[155] See *Messages from the Presidency on electricity market design and regional cooperation* (2016), Note to the Permanent Representatives Committee/Council, Annex, paragraph 4. http://data.consilium.europa.eu/doc/document/ST-8400-2016-INIT/en/pdf

Renewables Directive that facilitate a market based and more regionalised approach to renewables."[156]

5.1.4.2.Sub-option 1(b): Strengthening short-term markets

Sub-option 1(b) (strengthening short-term markets) includes the measures described under 1(a) (level playing field) and a set of additional measures, further enhancing the measures foreseen in the CACM and EB Guidelines (and are assumed as part of the baseline). As explained above, variable RES E have fundamentally different generation characteristics compared to traditional fuel based generation (e.g. variability, only short-term predictability). An important additional step would therefore be to have more liquid and better integrated short-term markets, going beyond what the implementation of technical implementing legislation ("Network Codes") will achieve, setting the ground for renewable energy producers to better access energy wholesale markets and to compete on an equal footing with conventional energy producers. Short-term markets will also allow Member States to share their resources across all "time frames" (forward trading, day-ahead, intraday and balancing), taking advantage of the fact that peaks and weather conditions across Europe do not occur at the same time.

Also, the closer to real time electricity is traded (supply and demand matched), the less the need for costly TSO interventions to maintain a stable electricity system. Although TSOs would have less time to react to deviations and unexpected events and forecast errors, the liquid, better interconnected balancing markets, together with the regional procurement of balancing reserves, would be expected to provide them with adequate and more efficient resources in order to manage the grid and facilitate RES E integration.

In order to support these actions and mainly in order to be able to optimally exploit interconnections along all "time frames", a number of measures are assumed to be taken: gate closure times could be brought closer to real-time to provide maximum opportunity for the market to balance its positions before it becomes a TSO responsibility and some harmonisation would be brought to trading products for intraday markets in order to further incentivize cross-border participation of market parties. The sizing of balancing reserves and their procurement would be harmonized in larger balancing zones, allowing to reap benefits of cross-border exchange of reserves and use of the most efficient reserves available.

At the same time, the integration of national electricity systems, from the market and operational perspectives, requires the enhancement of cooperation between TSOs. The creation of a number of regional operational centres ('**ROCs**'), with an enlarged scope of functions, an optimised geographical coverage compared to the existing regional security coordinators and with an enhanced advisory role for all functions, including the possibility to entrust them decision-making responsibilities for a number of relevant

[156] 31st EU Electricity Regulatory Forum, 13-14 June 2016, Draft Conclusions, §6. https://ec.europa.eu/energy/sites/ener/files/documents/Draft%20conclusions%20FINAL14June.pdf
https://ec.europa.eu/energy/sites/ener/files/documents/Draft%20conclusions%20FINAL14June.pdf

issues, could contribute to better TSO cooperation at regional level.[157] Measures on enhanced cooperation between TSOs could be accompanied by an increased level of cooperation between regulators and governments.[158]

All these options would be expected to strongly incentivize participation in the intraday and balancing markets, further increasing their liquidity, while at the same time minimizing TSOs' interventions.

Stakeholders' opinions: Most stakeholders agree with the need to speed up the development of integrated short-term (intraday and balancing) markets. A significant number of stakeholders argue that there is a need for legal measures, in addition to the technical network codes under development, to speed up the development of cross-border balancing markets. Many stakeholders note that the regulatory framework should enable RES E to participate in the market, e.g. by adapting gate closure times and aligning product specifications.

European Parliament: *"European Parliament [...][c]alls for the completion of the integration of internal market and balancing and reserve services by fostering liquidity and cross-border trading in all market timeframes; urges that efforts to achieve the ambitious goals of the Target Model regarding intraday and balancing markets be speeded up, starting with the harmonisation of gate closure times and the balancing of energy products[.]"*[159]

Council: *"An integrated European electricity market requires well-functioning short term markets and an increased level of cross-border cooperation with regard to day-ahead, intraday and balancing markets, without hampering the proper functioning of the networks, as this will enhance security of supply at lower costs for the system and consumers"*[160].

European Economic and Social Committee: *"The EESC underlines the particular importance of intraday trade as a way of ensuring meaningful trade involving VREs[variable renewable energies]"*[161].

European Electricity Regulatory Forum, Florence: *"The Forum supports the view that further steps are needed beyond agreement and implementation of the Balancing Guideline. In particular, further efforts should be made on coordinated sizing and cross--border sharing of reserve capacity. It invites the Commission to develop proposals as*

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157 For more details concerning policy measures for the establishment of ROCs, refer to Option 1 in Annex 2.3.

158 For more details concerning policy measures for the enhanced cooperation between regulators and governments, refer to Option 1 in Annex 3.4.

159 European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, § 46.

160 See *Messages from the Presidency on electricity market design and regional cooperation* (2016), Note to the Permanent Representatives Committee/Council, Annex, paragraph 6. http://data.consilium.europa.eu/doc/document/ST-8400-2016-INIT/en/pdf

161 31st EU Electricity Regulatory Forum, 13-14 June 2016, Draft Conclusions, §3.5. https://ec.europa.eu/energy/sites/ener/files/documents/Draft%20conclusions%20FINAL14June.pdf

part of the energy market design initiative, if the impact assessment demonstrates a positive cost---benefit, which also ensures the effectiveness of intraday markets"[162].

"The Forum Acknowledges the significant progress being made on the integration of cross - border markets in the intraday and day---ahead timeframes, and considers that market coupling should be the foundation for such markets. Nevertheless, the Forum recognises that barriers may continue to exist to the creation of prices that reflect scarcity and invites the Commission, as part of the energy market design initiative, to identify measures needed to overcome such barriers"[163].

"[T]he Forum invites the Commission to identify those aspects of national intraday markets that would benefit from consistency across the EU, for example on within---zone gate closure time and products that should be offered to the market. It also requests for action to increase transparency in the calculation of cross---zonal capacity, with a view to maximising use of existing capacity and avoiding undue limitation and curtailment of cross---border capacity for the purposes of solving internal congestions"[164].

"The Forum stresses that, whilst scarcity pricing in short---term markets is critical to creating the right signals, the importance of hedging opportunities and forward/future markets in creating more certainty for investors and alleviating risks for consumers must not be overlooked. Further, it considers that the Commission must recognise the risks of State Interventions undermining scarcity pricing signals"[165].

[162] 30th meeting of the European Electricity Regulatory Forum, Florence, 3-4 March 2015, Conclusions, §3, https://ec.europa.eu/energy/sites/ener/files/documents/Conclusions%20-%20Florence%20Forum%20-%20Final.pdf

[163] 30th meeting of the European Electricity Regulatory Forum, Florence, 3-4 March 2015, Conclusions, § 4, https://ec.europa.eu/energy/sites/ener/files/documents/Conclusions%20-%20Florence%20Forum%20-%20Final.pdf

[164] 30th meeting of the European Electricity Regulatory Forum, Florence, 3-4 March 2015, Conclusions, § 5, https://ec.europa.eu/energy/sites/ener/files/documents/Conclusions%20-%20Florence%20Forum%20-%20Final.pdf

[165] 30th meeting of the European Electricity Regulatory Forum, Florence, 3-4 March 2015, Conclusions, § 6, https://ec.europa.eu/energy/sites/ener/files/documents/Conclusions%20-%20Florence%20Forum%20-%20Final.pdf

5.1.4.3. Sub-option 1(c): Pulling demand response and distributed resources into the market[166]

Sub-option 1(c) (demand response/distributed resources) includes the measures described under 1(a) (level playing field) and 1(b) (strengthening short-term markets), as well as a set of additional measures, aiming at using the full potential of demand response, storage and distributed generation. The previous options would introduce a level playing field for all resources and improve the short-term market framework. They would, however, not include any measure intending to pull all the additional available potential from distributed resources into the market. Such resources are most importantly demand response, distributed RES E and storage.[167]

A significant part of the current costs for the electricity system stem from the new challenges of variable generation for the system, notably the increased need to deal with supply peaks and unexpected generation gaps. As the elecricity grid requires a constant balance of demand and supply, grid operators need to take costly measures. Demand response, distributed RES E and storage can play an important role to reduce these costs.

The measures considered under Option 1(c) bring demand response from all consumer groups, including residential and commercial consumers[168], and storage as additional resources into the market, especially to the balancing market. This would even further increase the flexibility of the electricity system and the resources for the TSOs to manage it. At the same time it should lead to much more efficient operation of the whole energy system.

This option would include more in particular:

Enabling consumers to directly react to price signals on electricity markets both in terms of consumption and production, by giving consumers access to a fit-for-purpose smart metering system, enabling suppliers to measure and settle electricity consumption close

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[166] This set of measures could have been introduced alternatively as Sub-Option 1(b), thus before the improved short-term market functioning related measures, as a further enhancement to the rules creating a level-playing field for all technologies. However, the benefits from the participation of these additional resources in the market are enhanced via their participation in the balancing markets and the procurement of reserves. Introducing this set of measures in the context of improved short-term market functioning therefore allows the full benefits of them to be realised. See also footnote 294, Section 6.1.7.

[167] RSCAS Research report (2015), "*Conceptual framework for the evolution of the operation and regulation of electricity transmission systems towards a decarbonised and increasingly integrated electricity system in the EU*" by J.-M.Glachant, J.Vasconcelos, V.Rious, states: *"EU has a target model for the EU internal market and for the transmission system operation. It has none for EU "RES pocket markets" and for the distribution system operation"*.

[168] As big industrial consumers are assumed to already participate directly in the market in Option 1(a) (level playing field), this sub-option extends the participation of demand response to all consumer groups (including residential and commercial consumers) who, because of their small individual loads, can enter the market only through third party service providers, e.g. aggregators. At the same time though the described measures are expected to significantly increase the DR potential for all categories, including industrial consumers who do not wish to engage directly in the market and by allowing DSOs to procure additional flexibility services.

to real time, as well as requiring suppliers to offer consumers electricity supply contracts with prices linked dynamically to the wholesale spot market that will enable consumers to directly react to price signals on electricity markets both in terms of consumption and production.

Box 4: Benefits and risks of dynamic electricity pricing contracts

The preferred policy option is to provide all consumers the possibility to voluntarily choose to sign up to a dynamic electricity price contract and to participate in demand response schemes. All consumers will however have the right to keep their traditional electricity price contract.

Dynamic electricity prices reflect – to varying degrees – marginal generation costs and thus incentivise consumers to change their consumption in response to price signals. This reduces peak demand and hence reduces the price of electricity at the wholesale market. Those price reductions can be passed on to all consumers. At the same time, suppliers can pass parts of their wholesale price risk on to those consumers who are on dynamic contracts. Both aspects can explain why, according to the ACER/CEER monitoring report 2015, on average existing dynamic electricity price offers in Europe are 5% cheaper than the average offer.

While consumers on dynamic price contracts can realise additional benefits from shifting their consumption to times of low wholesale prices they also risk facing higher bills in case they are consuming during peak hours. Such a risk is deemed to be acceptable if taking this risk is the free choice of the consumer and if he is informed accurately about the potential risks and benefits of dynamic prices before signing up to such a contract.

Aggregators are companies that act as intermediaries between the electricity system and distinct agents in the electricity system, mainly small, individual resoures but that exist in large numbers, and which are usually located in the distribution grid (consumers, prosumers and producers).[169] Developing a comprehensive framework for demand, supply and storage aggregators would facilitate their participation in the market and thus increase flexibility in the energy system and complement large generation connected to the transmission grid.[170] Larger storage facilities can be connected at distribution or transmission level, and provide services on a peer basis with other providers.

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[169] EPRG working paper 1616 (2016), *"Which Smart Electricity Services Contracts Will Consumers Accept?"* by L-L.Richter and M.G.Pollit states: *"By combining appropriate participation payments with sharing of bill savings, service providers could attract the number of customers required to provide the optimal level of demand response."*

[170] CIGRE paper C5-304 (2016), B. Guédou and A. Rigard-Cerison, RTE France says**:** *"One can learn, from French experience, that building an appropriate market for DSR requires to benefit from a strong political commitment (intense involvement from the administration, the regulatory authorities and the TSO) and to solve some key issues, requiring innovative answers both on the regulatory side and the technical side (e.g. role of aggregators / independent DR operators, adaptation of the regulatory framework to enable competition, role of TSOs and DSOs, data collection and privacy…)"*.

R&D results: The economic and technical viability of the concept of aggregation has already been demonstrated in European projects like: Integral, IDE4L, Grid4eu, INTrEPID, INCREASE, DREAM. The ability of small-scale RES to participate in the balancing market or contribute to solving grid congestion has been demonstrated in European projects like: V-Sync and MetaPV.

In order to pull all available resources into the market, it is also important to enable and incentivise DSOs, without compromising their neutrality as system operators, to manage their networks in a flexible and cost-efficient way, This could be achieved by establishing a performance-based remuneration framework for DSOs that would reward them for innovating and improving overall efficiency of their networks through synergies with other actors, making full use of energy storage, and/or investing in electronic communication infrastructure. This would be enabled by the deployment of intelligent infrastructure and by ensuring coherence with other Commission policies in the field of the Digital Single Market and the General Data Protection Regulation[171].

Measures under this option would also include defining the conditions under which DSOs may acquire flexibility services without distorting the markets for such services, and putting in place distribution tariff structures that send accurate price signals to all grid users. Such initiative would be aimed at facilitating the integration of the increasing amounts of variable RES E generation that will be connected directly to distribution grids in the future.

Stakeholders' opinions: Many stakeholders identified a lack of smart metering systems offering the full functionalities to consumers and dynamic electricity pricing (more flexible consumer prices, reflecting the actual supply and demand of electricity) as one of the main obstacles to kick-starting **demand side response**, along with the distortion of retail prices by taxes/levies and price regulation.

Other factors include market rules that discriminate against consumers or aggregators who want to offer demand response, network tariff structures that are not adapted to demand response and the slow roll-out of smart metering. Some stakeholders underline that demand response should be purely market driven, where the potential is greater for industrial customers than for residential customers. Many replies point at specific regulatory barriers to demand response, primarily with regards to the lack of a standardised and harmonised framework for demand reponse (e.g. operation and settlement). A number of respondents also underline the need to support the development of aggregators by removing obstacles for their activity to allow full market participation of renewables. Many submissions highlight the crucial role of scarcity pricing for kick-starting demand response at industrial and household level.

Regarding the role of DSOs, the respondents consider active system operation, neutral market facilitation and data hub management as possible functions for DSOs. Some stakeholders point at a potential conflict of interests for DSOs who are able to actively

[171] This would entail also close cooperation with TSOs, as elaborated for example in CIGRE paper C2-111: "*Increased cooperation between TSO and DSOs as precondition for further developments in ancillary services due to increased distributed (renewable) generation*", M.Kranhold, 50Hertz Transmission GmbH (2016)

menage their networks where these DSOs are also active in the supply business, emphasizing that the neutrality of DSOs should be ensured. A large number of the stakeholders stressed the importance of data protection and privacy, and consumer's ownership of data. Furthermore, a high number of respondents stressed the need of specific rules regarding access to data. As concerns a European approach on distribution tariffs, the views are mixed; the usefulness of some general principles is acknowledged by many stakeholders, while others stress that the concrete design should generally considered to be subject to national regulation.

European Parliament: *"European Parliament […] considers that this framework should promote and reward flexible storage solutions, demand-side response technologies, flexible generation, increased interconnections and further market integration, which will help to promote a growing share of renewable energy sources and integrate them into the market[.]"*[172]
"European Parliament[…] recalls that the transition to scarcity pricing implies improved mobilisation of demand response and storage, along with effective market monitoring and controls to address the risk of market power abuse, in particular to protect consumers; believes that consumer engagement is one of the most important objectives in the pursuit of energy efficiency, and that whether prices that reflect the actual scarcity of supply in fact lead to adequate investment in electricity production capacity should be evaluated on a regular basis[.]"[173]
"European parliament […][c]onsiders that energy storage has numerous benefits, not least enabling demand-side response, assisting in balancing the grid and providing a means to store excess renewable power generation; calls for the revision of the existing regulatory framework to promote the deployment of energy storage systems and other flexibility options, which allow a larger share of intermittent renewable energy sources (RES), whether centralised or distributed, with lower marginal costs to be fed into the energy system; stresses the need to establish a separate asset category for electricity or energy storage systems in the existing regulatory framework, given the dual nature – generation and demand – of energy storage systems[.]"[174]

Council: *"The future electricity retail markets should ensure access to new market players (such as aggregators and ESCO's) on an equal footing and facilitate introduction of innovative technologies, products and services in order to stimulate competition and growth. It is important to promote further reduction of energy consumption in the EU and inform and empower consumers, households as well as industries, as regards possibilities to participate actively in the energy market and respond to price signals, control their energy consumption and participate in cost-effective demand response solutions. In this regard, cost efficient installation of smart*

[172] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, § 5.
[173] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, § 10.
[174] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, § 28.

meters and relevant data systems are essential. Barriers that hamper the delivery of demand response services should be removed"[175].

European Electricity Regulatory Forum, Florence: *"The Forum recognises that the development of a holistic EU framework is key to unlocking the potential of demand Response and to enabling it to provide flexibility to the system. It notes the large convergence of views among stakeholders on how to approach the regulation of demand response, including: the need to engage consumers; the need to remove existing barriers to market access, including to third--‐party aggregators; the need to make available dynamic market--‐based pricing; the importance of both implicit and explicit demand response; and the cost--‐efficient installation of the required technology"*[176].

5.1.5. Option 2: Fully Integrated EU market

This option considers measures that would aim to deliver a single truly pan-European electricity market via relatively far-reaching changes to the current regulatory framework, aiming at the full integration of electricity markets and system operation, and at mobilising all available flexibility of the EU-wide system.

For a fully integrated EU market, one would need to significantly change the current regulatory approach of the internal market. The current EU wholesale market design of the Third Package provides for a coordination framework between grid operators and national regulators and sets some rules for certain issues which are relevant for cross-border exchange of electricity (e.g. coordinated electricity trading and grid operation measures). However, under the Third Package, regulatory decisions are in principle left to Member States, the 28 national regulators and the 42 European grid operators if not otherwise provided in the Third Package.

Leaving scope for national decision-making on trading and system operation may lead to inefficiencies due to unsufficiently coordinated and contradicting decisions. A more centralised regulatory approach could therefore be considered to achieve more integrated EU markets.

Under this option, procurement of balancing reserves would be performed directly at EU level, instead of a regional level. For system operation, this could mean shifting from a system of separate national TSOs to an integrated system managed by a single European Independent System Operator ("**EU ISO**"). System operation (including real time operation) and planning functions could be performed by this EU ISO, which would be competent for the whole Union.[177]

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[175] See *Messages from the Presidency on electricity market design and regional cooperation* (2016), Note to the Permanent Representatives Committee/Council, Annex, paragraph 8. http://data.consilium.europa.eu/doc/document/ST-8400-2016-INIT/en/pdf

[176] 31st EU Electricity Regulatory Forum, 13-14 June 2016, Draft Conclusions, §1. https://ec.europa.eu/energy/sites/ener/files/documents/Draft%20conclusions%20FINAL14June.pdf

[177] For more details on policy option concerning the establishment of an EU ISO, please refer to Option 3 in annex 2.3.

In order to optimally deal with congestion between countries and to let the market transmit the right price signals, this option would entail to move from zonal to nodal pricing[178]. The values of available transmission capacities would be calculated centrally and could be closely coordinated across market regions, thereby taking advantage of all information available among the TSOs in different grid arreas and also taking into account the interrelationship between different interconnectors. As a result, it is assumed that more interconnector capacity is made available to the market(s) and resources are expected to be utilized more efficiently across regions.

In general, Option 2 would not only entail coordination, approximation and harmonisation of selected topics relevant for national market and grid operation rules, but also to apply the same rules and specifications for products and services across the EU, including centrally fixed rules for electricity trading, for common EU-wide procurement of reserves and central system planning and operation. Such centralised integrated market would also provide for mandatory smart meter roll-out and a full EU framework for incentive-based demand response to better exploited demand reponse. Under Option 2, also distribution tariff structures would be harmonised, stronger unbundling rules for DSOs be created as well as harmonised renumeration methodologies that ensure DSOs' incentives to invest in innovative and efficient technologies.

ACER would need to gain significant competences and take over most NRAs' responsibilities directly or indirectly related to cross-border and EU-level issues. ENTSO-E would need to be formally separated from its members' interest and take up more competences.[179]

Such measures, intended to optimise the cost-efficiency and flexibility of the European electricity system, would involve going significantly beyond the measures described under Option 1, requiring also particularly far-reaching institutional changes.

Stakeholders' opinions: No stakeholder expressed support for the possibility of designing measures leading to the creation of a fully integrated EU electricity market. For example, as regards the establishment of an EU Independent System Operator, a number of stakeholders emphasized that while it is necessary to reinforce TSO coordination, this should take place through a step-wise regional integration of system operation

5.1.6. For Option 1 and 2: Institutional framework as an enabler

Each set of proposed measures under Options 1(a) to 1(c), as well as (2), will necessitate a different degree of reinforcement of the institutional framework of the EU's electricity

[178] Nodal Pricing is a method of determining prices in which market clearing prices are calculated for a number of locations on the transmission grid called nodes. Each node represents the physical location on the transmission system where energy is injected by generators or withdrawn by loads. The price at each node represents the locational value of energy, which includes the cost of the energy and the cost of delivering it, i.e. losses and congestion

[179] For more details on ACER's and ENTSO-E's enhanced competences in a fully integrated EU market, refer to Option 2 in Annex 3.4.

markets. Since the harmonisation of regulatory aspects (e.g. gate closure times, rules for the curtailment of cross-border capacities, bidding zones etc.) often has different economic impacts in different Member States, an institutional framework is needed to find the necessary compromises. Experience has shown that it will generally be more difficult to achieve ambitious harmonisation goals with an institutional framework that grants veto rights to each national regulator or TSO (i.e. in cooperative institutions applying unanimous decision-making). An alignment or harmonisation of aspects concerning the electricity market design is therefore more likely to happen with an institutional framework which applies (qualified) majority decision-making or which replaces the decision-making by 28 different regulators/TSOs by a central body which takes the decision in the European interest[180].

A robust institutional framework constitutes a pre-requisite for the integration and proper functioning of the EU market. For this reason, it is necessary that the institutional framework reflects the realities of the electricity system and the resulting need for regional cooperation as well as that it addresses existing and anticipated regulatory gaps in the energy market.

In order to effectively establish a level playing field between all potential market participants and resources (Sub-option 1(a) (level playing field)), it is necessary to reinforce ACER's competences at EU level in order to address regulatory gaps already identified in the implementation of the Third Package and ensure the oversight over entities and functions with relevance at EU level.

When markets and market regulation achieve a regional dimension (Sub-option 1(b)(strenghening short-term markets)), the institutional framework needs to be adapted accordingly, if it is to remain efficient and effective. Currently, the EU institutional framework is based on the complementarity of regulation at national and EU law. Hence, the regulatory framework would then need to be reinforced to address the need for additional regional cooperation. In this regard, ACER's competences and NRAs' cooperation at regional level should be enhanced, corresponding to increased regional TSO cooperation and to the implementation of network codes and guidelines at regional level. The mandate of ENTSO-E could be clarified to strengthen its obligation to take a European / internal market perspective and to emphasize its transparency and monitoring obligations. The role of power exchanges in cross-border electricity issues should be acknowledged and they should be involved in all regulatory procedures relevant for them. Finally the use of congestion income should be altered, increasing the proportion spent on investments that maintain or increase interconnection, thus creating the basis for the regional co-operation through a strongly interconnected system[181].

In order to facilitate distributed resources to participate in the market (Sub-option 1(c) demand response/distributed resources), DSOs must become more active at European level and have increased responsibilities and tasks, similar to those of the TSOs. Their

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[180] The transfer of decisions on cross-border cost allocation to the Director of ACER is one example of decision-making by an independent supranational body. See Article 12(6) of Regulation 347/2013 (TEN-E Regulation).

[181] As is in fact discussed under Option 1 of Problem Area II

role should be formalised into a European organisation with an efficient working structure to render their participation effective and independent. In particular, whereas DSOs are currently represented at EU level by four associations (Eurelectric, Geode, CEDEC and EDSO), none of these has the necessary characteristics to represent the sector by engaging in tasks that might include the codification of formal EU market rules: Either they or their members are listed as lobbyists on the EU Transparency Register, none of their memberships is representative of all EU DSOs, and none has the explicit mandate to represent EU DSOs in such activities.

Finally, Option 2 requires significantly restructuring the institutional framework, going beyond addressing the regulatory gaps and moving towards more centralised institutional structures with additional power and responsibilities, particularly for ACER and ENTSO-E.

Stakeholders' opinions: Opinions with regard to strengthening ACER’s powers are divided. There is clear support for increasing ACER's legal powers by many stakeholders. However, the option to keep the *status quo* is also visibly present, notably in the submissions from Member States and national energy regulators. While some stakeholders mentioned a need for making ACER'S decisions more independent from national interests, others highlighted rather the need for appropriate financial and human resources for ACER to fulfil its tasks.

With regard to ENTSO-E, stakeholders' positions are divided as to whether ENTSO-E needs strengthening remain divided. Some stakeholders mention a possible conflict of interest in ENTSO-E’s role – being at the same time an association called to represent the public interest, involved e.g. in network code drafting, and a lobby organisation with own commercial interests – and ask for measures to address this conflict. Some stakeholders have suggested in this context that the process for developing network codes should be revisited in order to provide a greater a balance of in interests.

Some submissions advocate for including DSOs and stakeholders in the network code drafting process. While a majority of stakeholders support governance and regulatory oversight of **power exchanges**, particularly as regards the market coupling operator function, other stakeholders are sceptical whether additional rules are needed for power exchanges given the existing rules in legislation on market coupling (in the CACM Guideline).

European Parliament: *"European Parliament […][n]otes the importance of effective, impartial and ongoing market monitoring of European energy markets as a key tool to ensure a true internal energy market characterised by free competition, proper price signals and supply security; underlines the importance of ACER in this connection, and looks forward to the Commission’s position on new and strengthened powers for ACER on cross-border issues[.]"*[182]

[182] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, § 70.

"European Parliament […][s]tresses that in most cases renewables are fed in at distribution system level, close to the level of consumption, and therefore calls for DSOs to play a greater role as facilitators and to be more closely involved in the design of European regulatory framework and in the relevant bodies when it comes to drawing up guidelines on issues of concern to them, such as demand-side management, flexibility and storage, and for closer cooperation between DSOs and TSOs at the European level[.]"[183]

5.1.7. Summary of specific measures comprising each Option

The following table summarizes the specific measures comprising each package of measures, as well the corresponding specific measure option considered under each high level option[184]. The detailed presentation and assessment of each measure can be found in the indicated Annex.

[183] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, § 63.

[184] The preferred options for the specific measures set out in the annex are highlighted in the table in green.

Table 6: Summary of Specific Measures investigated for Problem Area I

Specific Measures	Option 0	Option 1(a)	Option 1(b)	Option 1(c)	Option 2
	Baseline	**Level playing field**	**Option (a) + Strengthening short-term markets**	**Option 1(a), 1(b) + Demand response/distributed resources**	**Fully integrated markets**
Priority Access and Dispatch (Annex 1.1)	Maintain priority dispatch for RES, indigenous fuels and CHP (Annex 1.1.4 Option 0)	Abolish priority dispatch and introduce clear curtailment rules to replace priority access, with the exception of emerging technologies and small CHP and RES E plants (Annex 1.1.4 Options 2 and 3)			Fully abolish priority dispatch and access (Annex 1.1.4 Option 1)
+ Balancing Responsibility (Annex 1.2)	Financial balancing responsibility under EEAG (Annex 1.2.4 Option 0)	Balancing responsibility for all parties, with the exception of emerging technologies and small CHP and RES E plants (Annex 1.2.4 Option 2)			Full balancing responsibilities for all parties (Annex 1.2.4 Option 1)
+ RES providing non-frequency ancillary services (Annex 1.3)	Services continue to be provided by large conventional generation (Annex 1.3.4 Option 0)	Principles for transparent, non-discriminatory market-based framework for the provision of these services (Annex 1.3.4 Option 2)			EU market framework for such services (Annex 1.3.4 Option 1)
+ Reserves Sizing and Procurement (Annex 2.1)	National sizing of balancing reserves, frequency of procurement as today (e.g. many products, not necessarily separete upwards/downwards products) (Annex 2.1.4 Option 0)		Regional sizing and procurement of balancing reserves, daily procurement of upward/downward products (Annex 2.1.4 Option 2)		European sizing and procurement of balancing reserves, daily procurement of upward/downward products (Annex 2.1.4 Option 3)
+ Remove distortions for liquid short-term markets (Annex 2.2)	National non-harmonised intraday markets (Annex 2.2.4 Option 0)		Selected harmonisation of national intraday markets of gate closure times and products, with gradual implementation (Annex 2.2.4 Option 2)		Full harmonisation and coupling of intraday markets (Annex 2.2.4 Option 1)
+ TSO Co-operation (Annex 2.3)	Regional Security Coordinators (RSCs) to perform five tasks at regional level for national TSOs (Annex 2.3.4 Option 0)		Upgrade RSCs to Regional Operational Centres (ROCs) centralising additional functions over relevant geographical areas (Annex 2.3.4 Option 0)		Creation of Regional or EU Independent System Operators (Annex 2.3.4 Options 2 and 3)
+ Demand Response (Annex 3.1)	Smart meter rollout remains limited in geographical scope and functionalities, market barriers to aggregators persist, and the full potential of demand response and self-consumption remains untapped (Annex 3.1.4 Option 0)			Give consumers access to enabling technologies that will expose them to market price signals and a common European framework defining roles and responsibilities of aggregators (Annex 3.1.4 Option 2)	Mandatory smart meter roll out and full EU framework for incentive based demand response (Annex 3.1.4 Option 3)

Specific Measures	Option 0	Option 1(a)	Option 1(b)	Option 1(c)	Option 2
	Baseline	**Level playing field**	**Option (a) + Strengthening short-term markets**	**Option 1(a), 1(b) + Demand response/distributed resources**	**Fully integrated markets**
+ Ensuring that DSOs become active and remain neutral towards other market actors (Annex 3.2)	Broad variety of national approaches to DSO roles and responsibilities (Annex 3.2.4 Option 0)			Specific requirements and conditions for 'active' DSOs; Clarification of DSO's role in specific tasks; Enhanced DSO-TSO cooperation (Annex 3.2.4 Option 1)	EU framework for a specific set of DSO tasks and stricter unbundling rules (Annex 3.2.4 Option 2)
+ A performance-based remuneration framework for DSOs (Annex 3.3)	Broad variety of national approaches to DSO compensation (Annex 3.3.4 Option 0)			EU-wide principles on remuneration schemes; NRAs monitor the performance of DSOs (Annex 3.3.4 Option 1)	Fully harmonize remuneration methodologies (Annex 3.3.4 Option 2)
+ Distribution tariffs that send accurate price signals to grid users (Annex 3.3)	Broad variety of national approaches to distribution tariffs (Annex 3.3.4 Option 0)			EU wide principles to make tariffs structures become more transparent and more accurately reflect the impact of each system user on the grid, especially during different times of the day; NRAs to implement more detailed requirements (Annex 3.3.4 Option 1)	Fully harmonize distribution tariff structures through concrete requirements (Annex 3.3.4 Option 2)
+ Adapting Institutional Framework to reality of integrated markets (Annex 3.4 institutional framework)	Retain Status Quo (no change) (Annex 3.4.4 Option 0)	Adapt institutional framework to the new realities of the electricity system and the resulting need for additional regional cooperation and to address regulatory gaps (relevant to each respective policy sub-option) (Annex 3.4.4 Option 1)			Restructure the EU Institutional Framework providing for more centralised institutional structures (Annex 3.4.4 Option 2)

5.2. Options to address Problem Area II (Uncertainty about sufficient future generation investments and uncoordinated capacity markets)

5.2.1. Overview of the policy options

A number of Member States anticipate inadequate generation capacity in future years and plan to introduce or have already introduced unilateraly, unaligned capacity mechanisms. Capacity mechanisms remunerate the guaranteed availability of electricity resources (e.g. generation or demand response) rather than paying for electricity actually delivered. The current regulatory market design does provide for rules on capacity mechanisms[185]. While it does not prohibit nor encourage capacity mechanisms, the Third Package is, in principle, built on the concept of an "energy-only" market, in which generators are remunerated mainly based on the energy delivered[186]. Undistorted cross-border markets should provide for the necessary investment signals to ensure stable generation at all times. Price signals should drive production and investment decisions, whereas price differentials between different bidding zones should determine where facilities should ideally be located, provided that all assets are treated equally in terms of the risks and costs to which they are exposed and the opportunities for earning revenues from producing electricity i.e. they operate within a level playing field.

Several Options will be considered to address the concerns regarding investment certainty and fragmented approaches to CMs:

Box 5: Overview of the Policy Options for Problem Area II

Each policy option consists of a package of measures which act upon the drivers of the problem. Some of the options differ according to whether generators can only rely on energy market payments or whether they receive additional remuneration from CMs. Option 1 (Improved energy-only markets) would be based on additional measures to

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185 Capacity markets are only indirectly addressed, e.g. through the obligation for Member States under the Third Package to maximise cross-border capacities (see e.g. Art. 16 (3) of Regulation 714/2009) and to avoid unnecessary limitations of cross-border flows, e.g. through State Interventions.

186 It may be noted that generators can receive additional revenues from providing frequency reserves, which could be described as a form of (short-term) capacity markets.

further strengthen the internal electricity market (complementing the measures described above in options 1(a) (level playing field), 1(b) (strengthening short-term markets) and (c) (demand response/distributed resources) presented in Problem Area I). Under this option, CMs would no longer be allowed. Option 2 and 3 would also include the proposed measures to strengthen the internal energy market as presented in Option 1, but also propose possible measures to better align national CMs. The possibility to set up a mandatory EU-wide CM is described in Option 4.

The following sub-sections describe the policy options and the packages of measures they comprise. It then explains which options can be discarded at this stage, prior to assessment, as well as present other options that were considered but were discarded from the beginning. A table summarising all specific measures for each option is provided at the end of this section.

The relevant Annexes addressing the policy options below are: 4.1 to 5.2.

5.2.2. Option 0: Baseline Scenario – Current Market Arrangements

Under the baseline scenario, price formation on electricity wholesale markets is constrained, e.g. through price caps. Prices may not be able to reach levels which truly reflect the value of energy when the demand and supply balance is tight and, hence, electricity is scarce. Therefore price signals from wholesale markets would, in times of scarcity, be distorted and revenue streams of generators cannot properly reflect their value to the system. This affects, in particular, the remuneration of assets that can provide flexibility to the electricity system, regardless to whether this concerns flexible generation capacity, electricity storage or demand response.

At this stage most electricity markets in Europe face generation overcapacities. In this situation, price caps do in practice not matter – scarcity prices cannot be expected anyway. However, once old capacities will have exited the market and the power mix has adjusted (see in this regard the analyses presented in section 6.2.6.3), true price formation would be essential to produce signals for new investments. This could not happen as long as price caps exist.

Price signals are also not aligned with structural congestion in the transmission grid, thus not revealing the locations where investments would relieve congestion and production decisions. TSOs then can only operate sub-optimally the existing network and need to take frequent congestion management measures. Although the CACM Guideline provides a process for reviewing price or bidding zones, the current process lends itself to maintaining the *status quo* (mostly price zones along Member State borders), making this the most plausible assumption for the baseline. This is because there are likely to be competing interests at stake. In particular, some Member States are unlikely to want to amend bidding zones where it would create price differentials within their borders; it is sometimes considered to be right for all consumers to pay the same price within a

Member State, and for all producers to receive the same price. The current legislation does not, therefore, provide for the socially optimal solution to be agreed.[187]

Based on perceived or real resource adequacy concerns, several Member States take actions concerning the introduction of national resource adequacy measures or the imposition of regulatory barriers to decommissioning. These measures are usually based on national resource adequacy assessments and projections, which may substantially differ depending on the underlying assumptions made and the extent to which foreign capacities as well as demand side flexibility are taken into account in calculations. Some of these concerns and projections are a result of the current market arrangements.

The Commission's current tool to assess whether government interventions in support of resource adequacy are legitimate is state aid scrutiny. The EEAG require among others a proof that the measure is necessary, technological neutral and allows for explicit cross-border participation. However, the EEAG do not clarify how an effective cross-border CM regime could be deployed.

The baseline is common with the one presented in 5.1.2, with only two differences: (a) presence of price caps based on current practices and (b) existence of structural congestion in the transmission grid.

Stakeholders' opinions: None of the respondents to the public consultation took the view that the current market arrangements were sufficient and no further measures are required.

5.2.3. Option 0+: Non-regulatory approach

Whilst systematically considered[188], no such policy option could be identified.

This option would entail relying on existing legislation to improve the current market arrangements. The likelihood of seeing any meaningful change as a result of this process is minimal. Existing provisions under EU legislation are arguably not sufficiently clear and robust. In this regard, the Evaluation report indicates that the rules of the Third Energy Package appear to be insufficient to cope with the challenges facing the European electricity system.[189] In addition, certain areas, like resource adequacy, are not addressed in the Third Package. Consequently, the Evaluation report concludes that the Third Package does not not ensure sufficient incentives for private investments in the new generation capacities and network because of the minor attention in it to effective short-term markets and prices which would reflect actual scarcity.[190]

Voluntary cooperation has resulted in significant developments and a lot of benefits (e.g., the PLEF, whereby some Member States have voluntarily decided to cooperate and

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187 For more details concerning the deficiencies of current legislation concerning bidding zone configuration, see Sections 4.2.2 and 4.2.3 of Annex 4.2 to this Impact Assessment.
188 For each measure the opportunities for stronger enforcement has been assessed in the annexes.
189 See Section 7.3.1 and 7.3.3 of the Evaluation.
190 See Sections 7.3.2 of the Evaluation.

deliver a regional resource adequacy assessment). However it may not provide for appropriate levels of harmonisation across all Member States and certainty to the market and legislation is needed in this area to address the issues in a consistent way.

5.2.4. Option 1: Improved energy market - no CMs

Option 1 assumes that European electricity markets, if sufficiently interconnected and undistorted, can provide for the necessary price signals to incentivise investments into new generation. Wholesale markets would be strengthened by a set of specific measures aiming at improving price signals so as to deliver the necessary investments based only on price signals. CMs, whether at national, regional or European level would not be justifiable to secure electricity supplies under this option as the market should be incentivising investments.

Even if such price signals concern the spot price on the wholesale market corresponding to the day-ahead market, these prices are the reference for the forward market and would thus have a long-term effect. Having as a starting point the reformed market design as described in section 5.1.4.3[191], it is additionaly assumed that no administrative mechanisms directly affecting investments and price signals are allowed to be in place, in the form of CMs or (below Value of Lost Load[192] or 'VoLL') price caps. In the case of the latter this would be effected by ensuring that any technical limits imposed by power exchanges are merely that, and are raised in the event they are reached, and, in order to provide maximum investor confidence, an end-date, after which such limits must not be below VoLL.

The strengthened short and long-term markets and the participation of distributed generation offer the necessary flexibility required to integrate variable RES E into the market. Combined with the removal of (below VoLL) price caps,[193] the market should be able to drive investments towards the needed flexible assets, such as storage and demand response, and sufficient generating capacity. Furthermore, proper incentives are introduced aiming to unlock the flexibility that can be provided by existing assets, such as demand response and storage.

At the same time price signals could drive the geographical location of new investments and production decisions, via price zones aligned with structural congestion in the transmission grid. The location of the price zone borders would be decided through a robust regulatory decision-making process. Price differentials between these price zones should help determine where investments are needed and make the best use of natural resources (particularly important for RES E, but also for interconnectors) and, for those assets already deployed, which one will be producing. Such locational prices would also provide efficient signals for the location of demand – for example new energy intensive industries would choose to locate in areas where there is excess generation and therefore

[191] Sub-option 1(c) (demand response/distributed resources) from problem area I was used as the basis here, as it was identified as the preferred option when comparing the respective options in Section 7.1.

[192] Value of Lost Load is a projected value reflecting the maximum price consumers are willing to pay to be supplied with electricity

[193] For more detail on policy measures related to the removal of price caps, refer to Annex 4.1.

low prices.[194] Measures would also be taken to further restrict the practice of limiting cross-border capacity in order to deal with internal network contraints and, finally, measures would be taken to minimise, in the long-term, the most significant investment and operational distortions on generators arising as a result of network charges.[195]

Stakeholder's opinions: A majority of answering stakeholders is in favour an "energy-only" market (possibly augmented however with a strategic reserve, which is a form of a capacity market). Many stakeholders share the view that properly designed energy markets would make capacity mechanisms gradually redundant. Many generators and some governments disagree and are in favour of capacity remuneration mechanisms (assessed in Options 2, 3 and 4).

A large majority of stakeholders agreed that scarcity pricing is an important element in the future market design. While single answers point at risks of more volatile pricing and price peaks (e.g. political acceptance, abuse of market power), others stress that those respective risks can be avoided (e.g. by hedging against volatility).

A large number of stakeholders agreed that scarcity pricing should not only relate to time, but also to locational differences in scarcity (e.g. by meaningful price zones or locational transmission pricing). While some stakeholders criticised the current price zone practice for not reflecting actual scarcity and congestions within bidding zones, leading to missing investment signals for generation, new grid connections and to limitations of cross-border flows, others recalled the complexity of prices zone changes and argued that large price zones would increase liquidity.

Many submissions highlight the crucial role of scarcity pricing for kick-starting demand response at industrial and household level.

European Parliament:*"…[N]ational capacity markets make it harder to integrate electricity markets and run contrary to the objectives of the common energy policy, and should only be used as a last resort once all other options have been considered, including increased interconnection with neighbouring countries, demand-side response measures and other forms of regional market integration[.]"*[196]*"European Parliament […] [i]s sceptical of purely national and non-market-based capacity mechanisms and markets, which are incompatible with the principles of an internal energy market and which lead to market distortions, indirect subsidies for mature technologies and high costs for end-consumers; stresses, therefore, that any capacity mechanism in the EU must be designed from the perspective of cross-border cooperation following the completion of thorough studies on its necessity, and must comply with EU rules on competition and State aid; believes that better integration of national energy production*

194 For more detail on policy measures related to the improvement of locational signals, refer to Annex 4.2.
195 For more detail, refer to Annexes 4.3 and 4.4.
196 European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, Recital H.

into the EU energy system and the reinforcement of interconnections could reduce the need for, and cost of, capacity mechanisms[.]"[197]

5.2.5. Option 2: Improved energy market – CMs only when needed, based on a common EU-wide adequacy assessment)[198]

This Option includes the measures to strenghten the internal energy market (as described in Option 1 above), i.e. every Member State is assumed to have in place a well-functioning energy market.

In addition to Option 1 however, Member States would be allowed to implement national CMs, but only under certain conditions. Additional measures are proposed in order to avoid negative consequences of uncoordinated CMs for the functioning of the internal market, building on the EEAG' state aid Guidelines and the Sector Inquiry on CMs.

To address the problem of diverging and purely national assessments of the needs for CMs, ENTSO-E would be required under this option to propose a methodology for an EU-wide resource adequacy assessment. The upgraded methodology should be based on transparent and common assumptions[199] and ENTSO-E would carry out the assessment anually. The prerequisite for a Member State to implement a CM or prohibit capacity from exiting the market would be that ENTSO-E's assessment indicated a lack of generation capacity and where markets cannot be expected to close the gap. This would avoid that back-up capacities are developed based on a purely national perspective (i.e. national adequacy assessments, using different methodologies and not taking into account the generation potential across borders).

When proposing or applying CMs, Member States would need to introduce resource adequacy targets, which can be diverging (as an expression of their diverging preference for resource adequacy). The standards should be expressed in a unique format to become comparable across the EU – as Expected Energy Non Served ('**EENS**'), and it should be derived following a methodology provided by ENTSO-E which takes into account the value that average customers in each bidding zone put on electricity supplies (Value of Lost Load – 'VoLL').

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[197] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, § 24.

[198] Further elements of this option are presented in Annex 5.1.

[199] The ENTSO-E assessment should have the following characteristics:

i. It should cover all Member States
ii. It should have a granularity of Member State/ bidding zone level to enable the analysis of national/ local adequacy concerns;
iii. It should apply probabilistic calculations that consider dynamic characteristics of system elements (e.g. start-up and shut-down times, ramp up and ramp-down rates…)
iv. It should calculate generation adequacy indicators for all countries (LOLE, EENS, etc.)
v. It should appropriately take into account foreign generation, interconnection capacity, RES , storage and demand response
vii. Time span of 5-10 years

Stakeholders' opinions: There is almost a consensus amongst stakeholders on the need for a more aligned method for resource adequacy assessment. A majority of answering stakeholders supports the idea that any legitimate claim to introduce CMs should be based on a common methodology. When it comes to the geographical scope of the harmonized assessment, a vast majority stakeholders call for regional or EU-wide resource adequacy assessment, while only a minority favour a national approach. There is also support for the idea to align adequacy standards across Member States.

European Parliament: *"[…]stresses the importance of a common analysis of resource adequacy at regional level, facilitated by the Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators (ENTSO-E), and calls for the transmission system operators (TSOs) of neighbouring markets to devise a common methodology, approved by the Commission, to that end; highlights the enormous potential of strengthened regional cooperation[…]"*[200]

Council: *"Member States considering implementing capacity mechanism should take into account synergies of cross-border regional cooperation and avoid any disincentive for investment in interconnection, while minimising market distortion"*[201].

5.2.6. Option 3: Improved energy market - CMs only when needed, based on a common EU-wide adequacy assessment, plus cross-border participation[202]

Option 3 includes the measures to strenghten the internal energy market as described in Option 1 above. It also includes the requirement for national CMs to be justified by a European adequacy assessment (see Option 2). In addition, Option 3 would however provide for design rules for better compatibility between national CMs, also building on the EEAG state aid guidelines and the Sector Inquiry on CMs notably in order to facilitate cross-border participation ('blue-print') .

To date, in order to comply with EEAG, Member States have to individually organise, for each of their borders separately, the necessary cross-border arrangements involving a multitude of parties (e.g. resource providers, regulators, TSOs).

This option would provide a harmonised cross-border participation scheme across the EU by setting out procedures including roles and responsibilities for the involved parties (e.g. resource providers, regulators, TSOs).

200 European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, § 14.

201 See *"Messages from the Presidency on electricity market design and regional cooperation"* (2016), Note to the Permanent Representatives Committee/Council, Page 2. http://data.consilium.europa.eu/doc/document/ST-8400-2016-INIT/en/pdf

202 Further elements of this option are presented in Annex 5.

Stakeholders' opinions: Most of the stakeholders including Member States agree that a regional/European framework for CMs are preferable. Indeed, 85% of market participant respondents and 75% of public body respondents to the sector inquiry on Capacity Mechanisms[203] felt that rules should be developed at EU level to limit as much as possible any distortive impact of CMs on cross national integration of energy markets. Member States might instinctively want to rely more on national assets and favour them over cross-border assets. It is often claimed that in times of simultaneous stress, governments might choose to 'close borders' putting other Member States who might actually be in bigger need in trouble.

European Parliament: *"[...][c]alls for cross*-border *capacity mechanisms to be authorised only when the following criteria, inter alia, are met: a. the need for them is confirmed by a detailed regional adequacy analysis of the production and supply situation, including interconnections, storage, demand-side response and cross-border generation resources, on the basis of a homogeneous, standardised and transparent EU-wide methodology which identifies a clear risk to uninterrupted supply; b. there is no possible alternative measure that is less costly and less market-intrusive, such as full regional market integration without restriction of cross-border exchanges, combined with targeted network/strategic reserves; c. their design is market-based and is such that they are non-discriminatory in respect of the use of electricity storage technologies, aggregated demand-side response, stable sources of renewable energy and participation by undertakings in other Member States, so that there is no cross-border cross-subsidisation or discrimination against industry or other customers, and it is ensured that they only remunerate the capacity strictly necessary for security of supply; d. their design includes rules to ensure that capacity is allocated sufficiently in advance to provide adequate investment signals in respect of less polluting plants; e. sustainability and air quality rules are incorporated in order to eliminate the most polluting technologies (consideration could be given to an emissions performance standard in this connection) [...]"*[204]

5.2.7. Option 4: Mandatory EU-wide or regional CMs

Under this option based on regional or EU-wide resource adequacy assessments, entire regions or ultimately all EU Member States would be required to roll-out CMs on a mandatory basis. The design of the CMs would follow a EU 'blue print' (i.e. a set of design requirements for CMs), with the required resource adequacy target to be set at regional or EU level. This approach would assess *and address* adequacy concerns at a regional or EU level. Decisions on whether to introduce CMs or not would no longer be left with individual Member States, but an EU-wide CM would be created, as a mandatory additional layer to the "energy-only" market. Differences between Member States (e.g. whether all areas within larger regions actually face adequacy challenges, or network congestions) would not justify exception from the obligation to introduce a CM.

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[203] *"Interim Report of the Sector Inquiry on Capacity Mechanisms"* SWD(2016) 119 final. http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_swd_en.pdf

[204] European Parliament, *Report on Towards a New Energy Market Design* (2015/2322(INI)), Committee on Industry, Research and Energy, 21.6.2016, § 25.

5.2.8. Discarded Options

Option 0+ will not be further analysed as no means were identified to implement it.

Option 4 does not consider the significant regional differences when it comes to resource adequacy. The EU-wide or region-wide roll-out would disregard existing congestions in the European network and it would consequently over- or underestimate the resource adequacy in single bidding zones/ Member States belonging to a wider region. As a result CMs might need to be introduced in bidding zones/Member States that do not face any adequacy concerns. Alternatively, emerging resource adequacy problems in certain bidding zones/Member States might not be identified and addressed appropriately. In addition, as a number of Member States rely on energy-only markets to provide for the necessary investments in their power systems it would not be appropriate to force them to adopt CMs.

5.2.9. Summary of specific measures comprising each Option

The following table summarizes the specific measures comprising each package of measures, as well the corresponding specific measure option considered under each high level option[205]. The detailed presentation and assessment of each measure can be found in the indicated Annex.

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[205] The preferred options for the specific measures set out in the annex are highlighted in the table in green.

Table 7: Summary of Specific Measures Examined for Problem Area II

Specific Measures	Option 0	Option 1	Option 2	Option 3	Option 4
	Baseline (Current market arrangements)	**Improved energy market/ no CM**	**Improved energy market/ CMs only when needed, based on a common EU-wide adequacy assessment)**	**Improved energy market/ CMs only when needed, plus cross-border participation)**	**Mandatory EU-wide or regional CMs**
Specific Measures related to the Energy Market	As in section 5.1.2	As in section 5.1.4.3			
+ Price Caps (Annex 4.1)	Lower than VoLL (Annex 4.1.4 Option 0)	At VoLL (Annex 4.1.4 Option 2)			
+ Locational Price Signals (Annex 4.2)	Price Zones defined based on arrangements in CACM Guideline (4.2.4 Option 0)	Strengthened process for deciding on price zones, leading to the definition of zones based on systematic congestion in networks (4.2.4 Option 3)			Nodal Pricing (4.2.4 Option 1)
+ Transmission Tariff Structures (Annex 4.3)	Limited harmonisation of the methodologies setting transmission tariffs (Annex 4.3.4 Option 0)	More concrete principles on the setting of transmission tariffs and other network charges. (Annex 4.3.4 Option 2)			Full harmonisation of the methodologies setting transmission tariffs (Annex 4.3.4 Option 3)
+ Congestion Income (Annex 4.4)	Limited restrictions on the use of congestion income (Annex 4.4.4 Option 0)	Further prescription on the use of congestion income, with the aim of an even more European approach (Annex 4.4.4 Option 1)			
+ Resource Adequacy Plans (Annex 5.1)	National plans following different methodologies (Annex 5.1.4 Option 0)		Common EU-wide assessment by ENTSO-E becomes the basis for MS to introduce CMs (Annex 5.1.4 Option 3)		
+ Cross-border Participation of CMs (Annex 5.2)	No EU framework with rules for cross-border participation (Annex 5.2.4 Option 0)	N/A	No EU framework with rules for cross-border participation (Annex 5.2.4 Option 0)	Harmonized EU framework for cross-border participation (Annex 5.2.4 Option 1)	

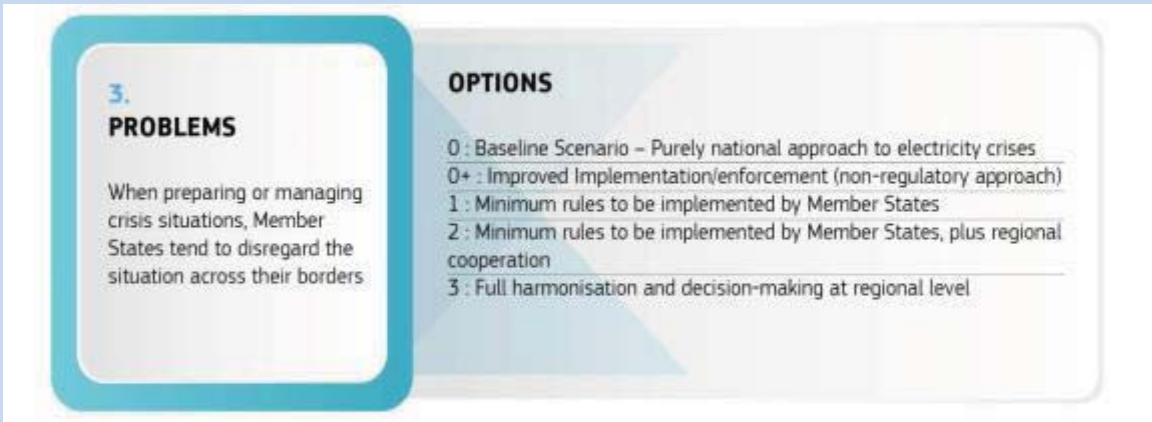
5.3. Options to address Problem Area III (When preparing or managing crisis situations, Member States tend to disregard the situation across their borders)

5.3.1. Overview of the policy options

With the intention to meet the objectives set out in the previous section, the Commission services have identified several policy options ranging from an enhanced implementation of the existing legislation to the full harmonization and decision making at regional level. Option 0 represents the baseline or the measures currently in place. Each policy option consists of a package of measures combining existing tools, possible updated and improved tools and new tools which act upon the drivers of the problem. This section finalizes with a table summarising all specific measures comprising each option.

The relevant Annex addressing the policy options below is Annex 6.

Table 8: Overview of the Policy Options for Problem Area III



3. PROBLEMS	OPTIONS
When preparing or managing crisis situations, Member States tend to disregard the situation across their borders	0 : Baseline Scenario – Purely national approach to electricity crises
	0+ : Improved Implementation/enforcement (non-regulatory approach)
	1 : Minimum rules to be implemented by Member States
	2 : Minimum rules to be implemented by Member States, plus regional cooperation
	3 : Full harmonisation and decision-making at regional level

5.3.2. Option 0: Baseline scenario – Purely national approach to electricity crises

Under the baseline scenario, Member States would continue identifying and addressing possible crisis situations based on a national approach, in accordance with their own national rules and requirements.

There would be no rules or structures facilitating and guaranteeing a proper identification of cross-border crisis situations[206] and ensuring that Member States take the necessary action to deal with them, in co-operation with one another. Whilst some co-operation between Member states could take place (e.g., between the Nordic countries as well as

[206] In the framework of the SESAME project (which was financed under FP7) tools were developed for the identification of grid and production plants vulnerabilities and for estimating the damage resulting from network failures. However, this project had a more national focus (in particular on Romania and Austria) and the identification and management of cross-border crisis was outside the scope of this project (https://www.sesame-project.eu/).

within the context of the PLEF[207]), in practice such cooperation would remain entirely voluntary, and might be hampered in practice by different national rules and procedures, and a lack of appropriate structures at regional and EU level.

Innovative tools[208] have been also developed for TSOs in the area of the system security in the last years, improving monitoring, prediction and managing secure interconnected power systems and preventing, in particular, cascading failures[209]. In addition, the recently adopted network codes and guidelines bring a certain degree of harmonisation on how to deal with electricity systems in different states (normal state, alert state, emergency state, black-out and restoration) and should bring more clarity as to how TSOs should act in crisis situations, and as to how they should co-operate with one another. However, network codes and guidelines focus on technical issues and co-operation between TSOs (in implementation of the current legal framework). They do not offer a framework ensuring a proper co-ordination and co-operation between Member States on how to prepare for and handle electricity crisis situations, in particular in situations of simultaneous scarcity.[210]

For instance, political decisions such as where to curtail, to whom and when, would still be taken nationally, by reference to very different national rules and regulations. In addition, any cross-border assistance in times of crisis would be hampered by a lack of common principles and rules governing co-operation, assistance and cost compensation. Finally, risks would still assessed and adressed on the basis of very different methods, and from a national perspective only.

Stakeholders' opinions: Stakeholders agree that the current framework does not offer sufficient guarantees that electricity crisis situations are properly prepared for and handled in Europe. They also take the view that, whilst network codes and guidelines will offer some solutions at the technical level, there is a need for a better alignment of national rules and cooperation at the political level[211].

207 Pentalateral Energy Forum, consisting of the Ministries, NRAs and TSOs of BENELUX, Germany, France, Austria, Switzerland.

208 ITESLA project (which was financed under FP7) developed methods and tools for the coordinated operational planning of power transmission systems, to cope with increased uncertainties and variability of power flows, with fast fluctuations in the power system as a result of the increased share of resources connected through power electronics, and with increasing cross-border flows. The project shows that the reliance on risk-based approaches for corrective actions can avoid costly preventive measures such as re-dispatching or reduced the overall risk of failure.

209 In addition the AFTER project (which was financed under FP7) also developed tools for TSOs to increase their capabilities in creating, monitoring and managing secure interconnected electrical power system infrastructures, being able to survive major failures and to efficiently restore service supply after major disruptions (http://www.after-project.eu/).

210 In addition, whilst the guidelines and codes require TSOs to co-operate, they do not require them to engage in joint action (e.g. through the ROCs).

211 See for examle the answers to the public consultation of the International Energy Agency, ENTSO-E.

5.3.3. Option 0+: Non-regulatory approach

As current legislative framework established by the SoS Directive set general principles rather than requires Member States to take concrete measures, better implementation and enforcement actions will be of no avail.

In fact, as the progress report of 2010 shows[212], the SoS Directive has been implemented across Europe, but such implementation did not result in better co-ordinated or clearer national policies regarding risk preparedness.

In addition, the evaluation of the SoS Directive has revealed the existence of numerous deficiencies in the current legal framework[213]. It highlights the ineffectiveness of the SoS Directive in achieving the objectives pursued, notably contributing to a better security of supply in Europe. Whilst some of its provisions have been overtaken by subsequent legislation (notably the Third Package and the TEN-E Regulation), there are still regulatory gaps notably when it comes to preventing and managing crisis situations.

The evaluation also reveals that the SoS Directive intervention is no longer relevant today as it does not match the current needs on security of supply. As electricity systems are increasingly interlinked, purely national approaches to preventing and managing crisis situations can no longer be considered appropriate. It also concludes that its added value has been very limited as it created a general framework but left it by and large to Member States to define their own security of supply standard. Whilst electricity markets are increasingly intertwined within Europe, there is still no common European framework governing the prevention and mitigation of electricity crisis situations. National authorities tend to decide, one-sidedly, on the degree of security they deem desirable, on how to assess risks (including emerging ones, such as cyber-security) and on what measures to take to prevent or mitigate them.

The recently adopted network codes and guidelines offer some improvements at the technical level, but do not address the main problems identified.

In addition, today voluntary cooperation in prevention and crisis management is scarce across Europe and where it takes place at all, it is often limited to cooperation at the level of TSOs. It is true that certain Member States collaborate on a voluntary basis in order to addresss certain of the problems identified (e.g. Nord-BER, PLEF). However, these initiatives have different levels of ambition and effectiveness, and they geografically cover only part of the EU electricity market. Therefore, voluntary cooperation will not be an effective tool to solve the problems identified timely in the whole EU.

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[212] *Report on the progress concerning measures to safeguard security of electricity supply and infrastructure investment* COM (2010) 330 final.

[213] See Evaluation of the EU rules on measures to safeguard security of electricity supply and infrastructure investment (Directive 2005/89/EC).

5.3.4. Option 1: Common minimum rules to be implemented by Member States

Under Option 1, Member States would have to respect a set of common rules and principles regarding crisis prevention and management, agreed at the European level ('minimum harmonisation'). In particular, Member States would be obliged to develop national **Risk Preparedness Plans** ('Plan') with the aim to avoid or better tackle crisis situations. Plans could be prepared by TSOs, but need to be endorsed at the political level. Plans should be based on an **assessment** of the most relevant crisis scenarios originated by rare/extreme risks. Such assesment would be carried out in a national context (as is the case today), but would have to based on a common set of rules. In particular, Member States would be required, for instance, to consider at least the following risks: a) rare/extreme natural hazards, b) accidental hazards which go beyond N-1, c) consequential hazards such as fuel shortage, d) malicious attacks (terrorist attacks, cyberattacks).

Plans would have to respect a set of common minimum requirements. They would need to set out who does what to prevent and to manage crisis situations, including in a situation of a crisis affecting more than one countrry at the same time. More specifically on **cybersecurity**, Member States would need to set out in the Plans how they will prevent and manage cyberattack situations. This would be combined with soft guidance on cybersecurity in the energy sector, based on the NIS Directive[214]. Member States would also be required to set out how they ensure that assets that are important from a security of supply perspective, are protected against undue influences in case ownership control changes.

Plans should be adopted by relevant governments / ministries, following an inclusive process, and (at least some parts of the Plans) should be rendered public. Plans should be updated on a regular basis.

In addition, under Option 1 there would be **new common rules and principles governing crisis management**, in replacement of the current Article 42 of the Electricity Directive, which allows Member States to take 'safeguard measures' in crisis situations. All crisis management actions (whether taken at the level of the TSOs or at the level of governments) would need to respect three principles:

- *'Market comes first'*: Non-market measures (such as obligatory demand reduction schemes) should only be introduced as a means of last resort, when duly justified, and should be temporary in nature. Use of such measures should not undermine market and system functioning;
- *'Duty to offer assistance':* Member States would be obliged to address electricity crisis situations, in particular situations of a simultaneous crisis, in a spirit of co-operation and solidarity. This means agreeing in advance on practical solutions on

[214] Directive (EU) 2016/1148 of the European Parliament and of the Council of 6 July 2016 concerning measures for a high common level of security of network and information systems across the Union, OJ L 194, 19.07.2016, p. 1-30.

e.g. where to shed load and how much in cross-border crisis situations, subject to financial compension (which is also to be agreed upon in advance).

- *'Transparency and information exchange'*: Member States should inform each other and the Commission without undue delay when they see a crisis situation coming (e.g., as a result of a seasonal outlook pointing at upcoming problems) or when being in a crisis situation. They should also be transparent about measures taken and their effect, both when taking them and afterwards.

The main benefits this option would bring is better preparedness, due to the fact that a common approach is followed across Europe, thus excluding the risk that some Member States being 'under-prepare'. In addition, better preparedness is likely to reduce the chances of premature market interventions, where Member States act in a transparent manner and on the basis of a clear set of rules. By imposing obligations to cooperate and lend assistance, Member States are also less likely to 'over-protect' themselves against possible crisis situations, which in turn will contribute to more security of supply at a lesser cost. Since a 'minimum' harmonisation approach would be followed, Member States would have still room to take account of national specificities, where needed and appropriate.

Stakeholders' opinions: A large majority of stakeholders is in favour of risk preparedness plans based on common rules and principles, as a tool to ensure a more common and more transparent approach. Consulted stakeholders[215] agree on the need for a common approach what Member States can do in crisis situations and call for more transparency.

5.3.5. Option 2: Common minimum rules to be implemented by Member States, plus regional co-operation

Option 2 would build on Option 1. It would include all common rules included in Option 1 (i.e., define a set of minimum obligations Member States would need to respect). In addition, it would put in place rules and tools to ensure that effective cross-border co-operation takes place, in a regional and EU context. Given the interlinked nature of EU's electricity systems, enhanced regional co-operation brings clear benefits when it comes to preventing and managing crisis situations.

First, under Option 2, there would be a **systematic assessment of rare/ extreme risks at the regional level**. The identification of crisis scenarios would be carried out by ENTSO-E, who would carry out such assessments in a regional context. To achieve this, ENTSO-E would be able to delegate all or part of its tasks to the ROCs. This regional approach would ensure that the risks originating across borders, including scenarios of a possible simultaneous crisis, are taken into account. The crisis scenarios identified by ENTSO-E would be also discussed in the Electricity Coordination Group, to ensure that a coherent and transparent approach is followed across Europe. For **cybersecurity**, building on Option 1, the Commission would propose the development of a network code/guidelines

[215] See for example the Public Consultation answers of the Dutch and Latvian Governments, GEODE, CEDEC, EDF UK, TenneT, Eurelectric and Europex welcoming risk preparendess plans.

which would ensure a minimum level of harmonization in the energy sector throughout the EU[216].

The Risk Preparedness Plans would contain two parts – **a part reflecting national measures and a part reflecting measures to be pre-agreed in a regional context**. The latter part includes in particular preparatory measures such as simulations of simultaneous crisis situations in neighbouring Member States **("stress tests" in regional context** organised by ENTSO-E who can delegate all or part of its tasks to the ROCs); procedures for **cooperation** with other Member States in different crisis scenarios, as well as agreements on **how to deal with simultaneous electricity crisis situations**. Through such regional agreements, Member States would be required to define in advance, in a regional context, how information will be shared, how they will ensure that markets can work as long as possible, and what kind of assistance will be offered accross borders, For instance, Member States would be required to agree in advance in which situations and according to what priorities customers would be curtailed in simultaneous crisis situations. The regional coordination of plans would build trust and confidence between Member States, which is crucial in times of crisis. It would also allow optimising scarce resources in times of crisis, whilst ensuring that markets can work as long as possible.

The regional parts of the Plans should be pre-agreed in a regional context. Such regionally co-ordinated plans would help ensure that increased TSO cooperation is effectively matched by a more structured cooperation between Member States.[217] For this reason, Member States would be called upon to co-operate and agree in the context of the same regional settings as are used for the ROCs. Effective regional co-operation and agreements would help ensure that electricity crisis situations are dealt with in the most effective manner, whilst respecting the needs of electricity consumers and systems at large.

To facilitate cross-border cooperation, Member States should designate one 'competent authority', belonging either to the national administration or to the NRA.

Additionally, **ENTSO-E** would be required to develop a **common method** for carrying out short-term risk assessments, to be used in the context of seasonal outlooks and weekly risk assessments by TSOs.

To allow for a precise monitoring, *ex-ante* and *ex-post*, of how well Member States' systems perform in the area of security of supply, harmonised security of supply

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[216] The network code/guidelines should take into account at least: a) methodology to identify operators of essential services for the energy sector; b) risk classification scheme; c) minimum cyber-security prerequisites to ensure that the identified operators of essential services for the energy sector follow minimum rules to protect and respond to impacts on operational network security taking the identified risks into account. A harmonized procedure for incident reporting for the energy sector shall be part of the minimum prerequisites.

[217] For cases of crisis, in particular simultaneous scarcity, also ENTSO-E sees a need for *"not only on a technical level but political cooperation"* and plans which *"should cover extreme crisis situations beyond the measures provided by e.g. network codes and RSCs services"* (Source: ENTSO-E (2016): *"Recommendations to the regulatory framework on risk preparedness (WS5)").*

indicators would be introduced, as well as obligation on Member States **to inform the Electricity Coordination Group and the Commission on crisis situations**, their impact and the measures taken. This would enhance transparency, comparability and mutual trust in neighbours.

Further, in this option, the role of the **Electricity Coordination Group**[218] would be reinforced, so that it can act as an effective forum to monitor security of supply in Europe and oversee the way (possible) electricity crisis situations are dealt with. For instance, the Group would be asked to review the cross-border crisis scenario's developed by ENTSO-E and to review *ex ante* risk preparedness plans put in place by Member States. The Group could issue recommendations and develop best practice. Overall, the reinforcement of its tasks and powers would contribute to enhance cooperation and to build trust and confidence among Member States.

Figure 7: Overview of measures in Option 2

Source: DG ENER

[218] The members of the Electricity Coordination Group are Member States authorities (ministries competent for Energy), National Regulatory Authorities, ACER and ENTSO-E.

Stakeholders' opinions: The majority of consulted stakeholders are in favour of regional coodination of risk preparedness plans[219] and a stronger co-ordinating role of the Electricity Coordination Group[220]. Various stakeholders make the case for a common methodology for assessing risks in various time horizons, to detect cross-border crisis situations and guarantee comparability of results[221]. Several stakeholders also see a need for clear rules and *ex-ante* cross-border agreements to ensure that markets function as long as possible in (simultaneous) crisis situations[222].

The **European Electricity Regulatory Forum, Florence:** The Florence Forum welcomes a more co-ordinated approach to risk preparedness based on risk preparendess plans and a common framework for how to deal with (simultaneous) crisis situations, including the principle that the market should act first[223].

"The Forum recognises the need for more co-ordination across Member States and clearer rules on coping with electricity crisis situations. It encourages the Commission to quickly bring the draft Emergency and Restoration Network Code forward for discussion with the Member States. It also welcomes the Commission's work on a new proposal on risk preparedness in the electricity sector and considers that risk preparedness plans and common framework for how to deal with critical situations should be its key builing blocks. It stresses the need that all action on risk preparedness should respect the principle that the market should act first."

The European Parliament[224] calls for more regional co-operation, notably as regards *'action to be taken in the event of an electricity crisis, in particular when such a crisis has cross-border effects,'* and calls on the Commission *'to propose a revised framework to that end*".

Council: The Council recognizes the responsibility of Member States for ensuring security of supply but sees a "*benefit from a more coordinated and efficient approach*", "*a necessity to work on a further harmonization of of methods for assessing norms and indicators for security of supply*" and "*a need to develop a more common approach to preparing for and managing crisis situations within the EU*".[225]

[219] See for example the Public Consultation answers of the Finish, Dutch, Norwegian governments, TenneT and the German Association of Local Utilities.
[220] See for example the Public Consultation answers of the Dutch government and ENTSO-E.
[221] See for example the Public Consultation answers of the Dutch government, EDF, ENTSO-E.
[222] See for example ENTSO-E's presentation on Capacity Mechanisms (TOP 2.4) from the Florence Forum in June 2016 (available here: https://ec.europa.eu/energy/en/events/meeting-european-electricity-regulatory-forum-florence).
[223] See conclusions from Florence Forum, March 2016, paragraph 10.
[224] See European Parliament: *Towards a New Energy Market Design* (2016), Werner Langen, paragraph 68.
[225] See *Messages from the Presidency on electricity market design and regional cooperation* (2016), Note to the Permanent Representatives Committee/Council, paragraph 7.

5.3.6. Option 3: Full harmonisation and decision-making at regional level

Building on Option 2, under Option 3 the **risk preparedness plans** would be developed on **regional level**. This would allow a harmonised response to potential crisis situations in each region. On **cybersecurity,** Option 3 would go one step further and nominate a dedicated body (agency) to deal with cybersecurity in the energy sector. The creation of the agency would guarantee full harmonisation on risk preparedness, communication, coordination and a coordinated cross-border reaction on cyberincidents.

Crisis would have to be managed according to the regional plans agreed among Member States. The Commission would determine the key elements of the regional plans such as: commonly agreed regional load-shedding plans, rules on customer categorisation, a harmonised definition of protected customers at regional level or specific rules on crisis information exchanges in the region.

Regarding **crisis handling**, under Option 3, a **detailed 'emergency rulebook'** would be put in place, containing an exhaustive list of measures that can be taken by Member States in crisis situations, with detailed indications as regards what measures can be taken, in what circumstances and when.

Stakeholders' opinions: The results of the public consultation showed that only few stakeholders were in favour of regional or EU wide plans. Some stakeholders mentioned the possibility to have plans on all three levels (national, regional and EU)[226].

Whilst stakeholders generally acknowledge the need for more commonality and more regional co-operation on risk prevention and management, there is no support for a fully harmonised approach based on rulebooks[227].

5.3.7. Discarded Options

Option 0+ was disregarded as no means for enhanced implementing of the existing acquis were identified.

5.3.8. Summary of specific measures comprising each Option

The following table summarizes the specific measures to be taken under each option [228]. A more detailed discussion can be found in annex.

[226] See for example the Public Consultation answers of Latvian government, EDSO, GEODE, Europex.
[227] See for example the Public Consultation answers of the Finish and German governments.
[228] The preferred options for the specific measures set out in the annex are highlighted in the table in green.

Table 8: Sumary of Specific Measures Examined for Problem Area III

Specific Measures	Option 0	Option 0+	Option 1	Option 2	Option 3
	Baseline	Non-regulatory approach	Common minimum EU rules for prevention and crisis management	Common minimum EU rules plus regional cooperation, building on Option 1	Full harmonisation and full decision-making at regional level, building on Option 2
Assessments	Rare/extreme risks and short-term risks related to security of supply are assessed from a national perspective. Risk identification & assessment methods differ across Member States.	This option was disregarded as no means for enhanced implementing of the existing acquis nor for enhanced voluntary cooperation were identified.	Member States to identify and assess rare/extreme risks based on common risk types.	ENTSO-E to identify cross-border electricity crisis scenarios caused by rare/extreme risks, in a regional context. Resulting crisis scenarios to be discussed in the Electricity Coordination Group. Common methodology to be followed for short-term risk assessments (ENTSO-E Seasonal Outlooks and week-ahead assessments of the RSCs).	All rare/extreme risks undermining security of supply assessed at the EU level, which would be prevailing over national assessment.

Plans	Member States take measures to prevent and prepare for electricity crisis situations focusing on national approach, and without sufficiently taking into account cross-border impacts. No common approach to risk prevention & preparation (e.g., no common rules on how to tackle cybersecurity risks).		Member States to develop mandatory national Risk Preparedness Plans setting out who does what to prevent and manage electricity crisis situations. Plans to be submitted to the Commission and other Member States for consultation. Plans need to respect common minimum requirements. As regards cybersecurity, specific guidance would be developed.	Mandatory Risk Preparedness Plans including a national and a regional part. The regional part should address cross-border issues (such as joint crisis simulations, and joint arrangements for how to deal with situations of simultaneous crisis) and needs to be agreed by Member States within a region. Plans to be consulted with other Member States in the relevant region and submitted for prior consultation and recommendations by the Electricity Coordination Group. Member States to designate a 'competent authority' as responsible body for coordination and cross-border cooperation in crisis situations. Development of a network code/guideline addressing specific rules to be followed for the cybersecurity. Extension of planning & cooperation obligations to Energy Community partners.	Mandatory Regional Risk Preparedness Plans, subject to binding opinions from the European Commission. Detailed templates for the plans to be followed. A dedicated body would be created to deal with cybersecurity in the energy sector.

Crisis management	Each Member State takes measures in reaction to crisis situations based on its own national rules and technical TSO rules. No co-ordination of actions and measures beyond the technical (system operation) level. In particular, there are no rules on how to coordinate actions in simultaneous crisis situations between adjacent markets. No systematic information-sharing (beyond the technical level).		Minimum common rules on crisis prevention and management (including the management of joint electricity crisis situations) requiring Member States to: (i) not to unduly interference with markets; (ii) to offer assistance to others where needed, subject to financial compensation, and to; (iii) inform neighbouring Member States and the Commission, as of the moment that there are serious indications of an upcoming crisis or during a crisis.	Minimum obligations as set out in Option 1. Cooperation and assistance in crisis between Member States, in particular simultaneous crisis situations, should be agreed ex-ante; also agreements needed regarding financial compensation. This also includes agreements on where to shed load, when and to whom. Details of the cooperation and assistance arrangements and resulting compensation should be described in the Risk Preparedness Plans.	Crisis is managed according to the regional plans, including regional load-shedding plans, rules on customer categorisation, a harmonized definition of 'protected customers' and a detailed 'emergency rulebook' set forth at the EU level.
Monitoring	Monitoring of security of supply predominantly at the national level. ECG as a voluntary information exchange platform.		Systematic discussion of ENTSO-E Seasonal Outlooks in ECG and follow up of their results by Member States concerned.	Systematic monitoring of security of supply in Europe, on the basis of a fixed set of indicators and regular outlooks and reports produced by ENTSO-E, via the Electricity Coordination Group. Systematic reporting on electricity crisis events and development of best practices via the Electricity Coordination Group.	A European Standard (e.g. for EENS and LOLE) on Security of Supply could be developed to allow performance monitoring of Member States.

5.4. Options to address Problem Area IV (Slow deployment and low levels of services and poor market performance)

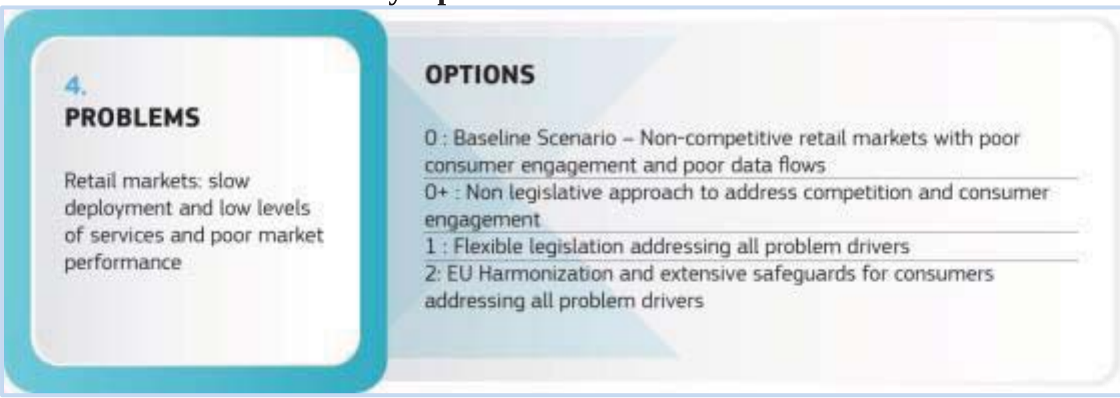
5.4.1. Overview of the policy options

To recap, the drivers in this Problem Area are:

- Low levels of competition on retail markets;
- Low levels of consumer engagement;
- Market failures that prevent effective data flow between market actors.

Each policy option consists of a package of measures that addresses the problem drivers in a different way and to a different extent. They aim to tackle the existing competition and technical barriers to the emergence of new services, better levels of service, and lower consumer prices, whilst ensuring the protection of energy poor consumers.

Box 5: Overview of the Policy Options for Problem Area IV



In the following sub-sections the policy options and the packages of measures they comprise are described. This section is closed by a table summarising all specific measures comprising each option.

The relevant annexes addressing the policy options below are: 7.1 to 7.6.

5.4.2. Option 0: Baseline Scenario - Non-competitive retail markets with poor consumer engagement and poor data flows

Under this option no new legislation is adopted, there are no further efforts to clarify the existing legislation through guidance, and no additional work through non-regulatory means to address the problem drivers. It assumes that the future situation will remain more or less the same as today.

Stakeholders' opinions: A significant number of stakeholders consider that the level of competition in retail markets is too low and there is no record of significant support for current market arrangements and their organic development. The sole exception is on billing information, where energy suppliers and industry associations indicate that there may be little scope for EU action to ensure bills facilitate consumer engagement in the market due to subsidiarity considerations.

5.4.3. Option 0+: Non-regulatory approach to address competition and consumer engagement

Under this option, the problem drivers are addressed to the greatest extent possible without resorting to new legislation. This means strengthening enforcement to tackle cases of the non-transposition or incorrect application of existing legislation, new Commission guidance to tackle implementation issues related to difficulties in interpreting the existing legislation, and examining new soft law provisions to address gaps in the legislation itself.

To improve competition, bilateral consultations are held with Member States to progressively phase out price regulation, starting with prices below costs. Should it be clear that Member State interventions in price setting are not proportionate, justified by the general economic interest or not compliant with any other condition specified in the current EU acquis[229], then enforcement action is taken under the existing *acquis* and recent Court judgements, which require these criteria. Section 7.1.1 of the Evaluation argues that the regulation of electricity and gas prices limits consumer choice, restricts competition, and discourages investment.

To improve consumer engagement, the Commission issues an interpretative note on the existing provisions in the Electricity and Gas Directives covering switching-related fees. Section 7.1.1 and Annex IV of the Evaluation show that the current framework remains both complex and open to interpretation with regard to the nature and scope of certain key obligations.

The Commission works to ensure the dissemination and uptake of the key cross-sectorial principles for comparison tools. Enforcement action follows. Nevertheless, Section 7.3.5 and Annex V of the Evaluation show that the relevance of the existing legislation is challenged by the fact that it is not adapted to reflect new ways of consumer-market interaction, such as through comparison tools.

The Commission also develops a Recommendation on energy bills that builds upon the recommendations prepared by the Citizen's Energy Forum's Working Group on e-Billing and Personal Energy Data Management[230]. Section 7.1.1 and Annex V of the Evaluation show that there is poor consumer satisfaction with energy bills, and poor awareness of information conveyed in bills. This suggests that there may still be scope to improve the comparability and clarity of billing information.

Finally, to better protect energy poor and vulnerable consumers[231], the Commission establishes the EU Energy Poverty Observatory which will contribute to the sharing of

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[229] Article 3(2) of the Electricity Directive and of the Gas Directive

[230] https://ec.europa.eu/energy/sites/ener/files/documents/20131219-e-billing_energy_data.pdf

[231] As a result of the Third Energy Package, Member States have to defined and protect vulnerable consumers in energy markets. The evaluation of the provisions related to consumer vulnerability found the definitions of vulnerable consumers to vary widely across Member States. ACER grouped these definitions in two groups (i) explicit definitions when characteristics of vulnerability are stated in the definition such as age, income, or health; and (ii) implicit definitions when vulnerability is linked to be beneficiary of a social support measure. A study commissioned by DG ENER concluded that energy

good practices and strengthens enforcement around existing requirements for National Regulatory Authorities to monitor disconnection rates – an area identified as lacking in the Evaluation (Section 7.1.1 and Annex III).

However, no action is taken to address the market failures that prevent effective data flow between market actors. As this involves tackling possible conflicts of interest among market actors, non-regulatory measures were not deemed appropriate to credibly addressing this problem driver. Section 7.3.6 and Annex IX of the Evaluation show that the current legislation was not designed to address currently known challenges in managing large, commercially valuable consumption data flows.

By tackling regulatory interventions in price setting, this option would enable suppliers to profitably develop value-added products, thus fostering innovation in energy retail markets. It would also promote the consumer-driven uptake of such innovative products by addressing switching fees, unreliable comparison tools and unclear bills – each a key barrier to consumer engagement.

Stakeholders' opinions: There are no explicit opinions among the stakeholders on a non-regulatory approach. However, some of the points raised by the stakeholders, like increased transparency on switching suppliers, exit fees, comparison tools as well as transparent bills, may be addressed by non-regulatory measures.

5.4.4. Option 1: Flexible legislation addressing all problem drivers

Under this option, all problem drivers are addressed through new legislation that provides Member States leeway to adapt their laws to the conditions in national markets.

To improve competition, Member States progressively phase out blanket price regulation by a deadline specified in new EU legislation, starting with prices below costs. Transitional, targeted price regulation for vulnerable consumers is permitted (e.g. in the form of social tariffs), allowing a case-by-case assessment of the proportionality of exemptions to price regulation that takes into account the social and economic particularities in Member States.

To both improve competition and reduce transaction costs in the market, consumer data management rules that can be applied independently of the national data-management model are put in place. These include criteria and measures to ensure the impartiality of market actors involved in data handling, as well as the implementation of standardised, national data formats to facilitate data access. These measures aim at eliminating barriers to entry associated with data access, and helping all market actors provide a higher level of service to consumers through the efficiencies that information technology offers.

To increase consumer engagement, the use of contract termination fees is restricted. Such fees are only permissible for the early termination of fixed-term contracts, and they must be cost-reflective. Consumer confidence in comparison websites is fostered through

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poverty is usually a narrower term than vulnerability as it mostly refers to lack of affordability of energy services.

national authorities implementing a certification tool for the most useful and reliable websites in their markets. In addition, high-level principles ensure that energy bills are clear, easy to understand, and free from unnecessary information, whilst leaving Member States some scope to tailor billing format and content to national requirements. Certain information elements in bills would be mandatory and would need to be prominently displayed to facilitate the comparison of offers and switching.[232]

Finally, to better protect energy poor and vulnerable consumers, an improved, principle-based EU legal framework to support Member State action on vulnerable and energy poor consumers is put in place. A generic adaptable, definition of energy poverty based on household income and energy expenditure is included in the legislation for the first time. Member States would measure and report energy poverty with reference to household income and energy expenditure, and NRAs would publish the number of disconnections due to non-payment – figures they should already be collecting under the current legislation. These actions are taken cumulatively, on top of the non-regulatory measures on energy poverty described in Section 5.4.3.

These measures build upon the existing provisions on energy poverty in the Electricity and Gas Directives which state that Member States must adress energy poverty where it is identified. They offer the necessary clarity about the meaning of energy poverty, as well as, the transparency with regards to the number of household in energy poverty. Better monitoring of energy poverty across the EU will, on one hand, help Member States to be more alert about the number of households falling into energy poverty, and on the other hand, peer pressure will also encourage Member States to put in place measures to reduce energy poverty. Since currently available data can be used to measure energy poverty, the administrative cost is limited[233]. Likewise, the actions proposed do not condition Member States on their primary competence of social policy, hence, respecting the principle of subsidiarity.

Taken together, this option would strongly promote innovation on retail markets by ensuring that new entrants and energy service companies receive non-discriminatory access to consumer data – access that will allow these market actors to develop and offer the value-added products that (integrated) incumbents have not. A firm commitment to phase out blanket price regulation would enable suppliers in many Member States to differentiate their offers to consumers through non-price competition. And by tackling financial barriers to switching, improving the availability of comparison tools and helping consumers understand important information in their bills; this option would increase consumer engagement with the market and the selective pressure for new services.

[232] EPRG Working paper 1515 (2015), "*Why Do More British Consumers Not Switch Energy Suppliers*?" by X. He D. Reiner: *"We conclude that policies which emphasize simplification of energy tariffs, increasing convenience of switching, improving consumers' concerns about energy issues, improving consumers' confidence to exercise switch are likely to increase consumer activity."*

[233] See Annex 7.1, Table 16.

Stakeholders' opinions: Feedback indicates that the general principles put forward as part of Option 1 would likely enjoy broad support amongst stakeholders. The sole exception would be the measures on billing information, where energy suppliers and industry associations have stated that there may be little scope for EU action. However, even here, the general principles proposed in this option would give broad leeway to Member States to tailor national requirements to the conditions and consumer preferences in each market.

5.4.5. Option 2: EU Harmonization and extensive safeguards for consumers addressing all problem drivers

Under this option, all problem drivers are addressed through new legislation that aims to provide maximum safeguards for consumers and the extensive harmonisation of Member State action throughout the EU.

To improve competition, Member States progressively phase out all blanket price regulation, starting with prices below costs, by a deadline specified in new EU legislation, as per Option 1 (flexible legislation). However, exemptions to price regulation are defined at the EU level in terms of either: a) a price threshold to be defined based on principles ensuring coverage of the cost incurred by the energy undertakings above which Member States may set retail prices; and/or b) a consumption threshold below which household may benefit from a regulated tariff.

To both improve competition and reduce transaction costs in the market, a standard consumer data handling model is enforced. This assigns the responsibility for data handling to a neutral market actor, such as a TSO or independent third-party, eliminating all possibility of conflicts of interest. Nationally standardised formats are devised to facilitate data access to all market actors concerned, including cross-border access.

To increase consumer engagement, all switching-related fees are banned, including contract termination fees. NRAs establish comparison websites to ensure consumers have access to at least one neutral comparison resource, alongside private sector offerings. In addition, the format and content of energy bills is partially harmonized through the inclusion of a standard 'comparability box' that prescriptively presents key information in exactly the same way in every EU bill.

Finally, to better protect energy poor and vulnerable consumers, a uniform EU framework to monitor energy poverty and reduce disconnections is put in place. A specific, harmonised definition of energy poverty is included in EU legislation referring to households that fall below the poverty line after meeting their required energy needs. In order to measure energy poverty, Member States survey the energy efficiency of their national housing stock and calculate the amount of energy, and costs, required to make all housing comfortable. These survey results are reported to the Commission.

In addition, a host of preventive measures on disconnections are put in place: (i) Member States are to give all customers at least two months (approximately 40 working days) notice before a disconnection from the first unpaid bill; (ii) before a disconnection, all customers receive information on sources of support, and are offered the possibility to delay payments or restructure their debts; and (iii) the disconnection of vulnerable consumers is prohibited in winter.[234] These actions are taken cumulatively, on top of the non-regulatory measures on energy poverty described in Sections 5.4.3.

As with Option 1 (Flexible legislation), this option would strongly promote innovation on retail markets through non-discriminatory access to consumer data, a firm commitment to phase out blanket price regulation, and by tackling barriers to consumer engagement. However, any negative impacts to competition resulting from the stronger, and more costly, safeguards for the vulnerable and energy poor may also reduce the availability of new services. In addition, Member States may be better suited to design disconnection safeguard schemes to ensure that synergies between general national social service provisions and disconnection safeguards are achieved.

Stakeholders' opinions: Whilst many stakeholders support the objectives Option 2 aims to achieve, several have flagged reservations regarding the prescriptive approach to achieving them. In particular, NRAs have voiced their unease over an over-prescriptive EU billing format, and recommend that the decision on whether or not to allow contract exit fees is best taken at the national level. NRAs also point out that it is their role to define the appropriate methodologies for applicable price regulation. Most of the Member States consider that the model for data handling should be best decided at national level. And finally, whilst many stakeholders have supported comparison tool accreditation schemes (Option 1 – flexible legislation), none have called for government authorities to provide comparison tools exclusively.

5.4.6. Summary of specific measures comprising each Option

The following table summarizes the specific measures comprising each package of measures, as well the corresponding specific measure option considered under each high level option.[235] The detailed presentation and assessment of each measure can be found in the indicated Annex.

[234] Similar legislation is already in place in 14 Member States.

[235] The preferred options for the specific measures set out in the annex are highlighted in the table in green.

Table 9: Summary of Specific Measures Examined for Problem Area IV

Specific Measures	Option 0	Option 0+	Option 1	Option 2	
	Baseline	**Non-regulatory approach**	**Flexible legislation**	**Harmonization and extensive consumer safeguards**	
Energy poverty and disconnection protection (Annex 7.1)	Sharing of good practices(Annex 7.1.4 Option 0)	EU observatory for energy poverty. Sharing of good practices and increase efforts to correctly implement legislation (Annex 7.1.4 Option 0+)	Introducing a generic adaptable, definition of energy poverty in EU legislation, and setting an EU framework to monitor energy poverty (Annex 7.1.4 Option 1)	Introducing a specific, harmonised definition of energy poverty in EU legislation, a comprehensive EU framework to monitor energy poverty based on an energy efficiency survey of the housing stock, and a host of preventive measures to avoid disconnections (Annex 7.1.4 Option 2)	
Price regulation (Annex 7.2)	Making use of existing acquis to continue bilateral consultations and enforcement actions to restrict price regulation to proportionate situations justified by manifest public interest (Annex 7.2.4 Option 0)		Requiring MS to progressively phase out price regulation for households, starting with prices below costs, by a deadline specified in new EU legislation, while allowing transitional, targeted price regulation for vulnerable customers (Annex 7.2.4 Option 1)	Requiring MS to progressively phase out price regulation for households below a certain consumption threshold to be defined in new EU legislation or by MS, with support from Commission services (Annex 7.2.4 Option 2a)	Requiring MS to phase out below cost price regulation by a deadline specified in new EU legislation (Annex 7.2.4Option 2b)
Data management (Annex 7.3)	Member States are primarily responsible on deciding roles and responsibilities in data handling (Annex 7.3.4 Option 0)		EU data management rules that can be applied independently of the national data-management model (Annex 7.3.4 Option 1)	A standard EU data management model (data hub) (Annex 7.3.4 Option 2)	
Consumer engagement (Annexes 7.4, 7.5 and 7.6)	Lacklustre consumer engagement persists, diminishing the demand for new services and competitive pressure in the market	Improved EU guidance and Recommendations on switching-related charges and comparison tools (Annexes 7.4.4, and 7.5.4 Option 0+)	Flexible legislative measures to further limit switching-related charges, establishing a certification scheme to improve consumer confidence in comparison tools, and making information in bills clearer through minimum content requirements (not format) (Annexes 7.4.4, 7.5.4 and 7.6.4 Option 1)	Outlawing all switching-related charges, making all national authorities offer (or fund) an independent comparison tool, and full EU harmonization of the presentation of certain information in bills (Annexes 7.4.4, 7.5.4 and 7.6.4 Option 2)	

6. ASSESSMENT OF THE IMPACTS OF THE VARIOUS POLICY OPTIONS

This section assesses the impacts of the options under each Problem Area. The analysis focuses on the broad impacts of those options. The impacts of the specific measures included in each option are assessed in more detail in separate annexes attached to this impact assessment.

Each option was assessed both quantitatively and qualitatively, in an effort to capture at the highest possible detail the impacts of the underlying measures within each option. When reliable quantitative analysis or information was not available, the assessment could only be performed qualitatively, based on specific criteria.

6.1. Assessment of economic impacts for Problem Area I (Market design not fit for an increasing share of variable decentralized generation and technological developments

6.1.1. Methodological Approach

6.1.1.1.Impacts Assessed

The market design options are examined on the basis of their effectiveness in addressing the identified problems and achieving the desired objectives, while at the same time facilitating the delivery of the 2030 climate and energy targets[236] in a cost-efficient and secure way for the whole of Europe.

As the examined measures focus on the better functioning of the electricity markets[237], economic impacts are in particular analysed with respect to competition, cost-efficiency, better utilization of resources, as well as impacts on security of electricity supply.

The effect of the measures on the wholesale markets will induce indirect social impacts and have limited effect on innovation and research. The effects of energy market related polices on employment are primarily associated with the policy measures seeking to secure the achievement of the 2030 decarbonisation objectives[238]. They will therefore not be assessed in-depth for all options.

Some indirect environmental impacts are also expected, due to the different types of fuel used for power generation, as a well-functioning flexible electricity market would incentivize the increase of low carbon generation.

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[236] See: http://ec.europa.eu/clima/policies/strategies/2030/index_en.htm .

[237] Note that these options are not touching the issue of investment, which is examined under Problem Area II. Therefore the same power generation mix is assumed for all options.

[238] Reference is hence made to the impacts assessments for the EE and RED II initiatives and the one elaborated in the context of Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, "*A policy framework for climate and energy in the period from 2020 up to 2030*" (SWD(2014) 15 final)

Other significant impacts, direct or indirect, are not expected for the examined options, unless specifically noted.

The assessment is presented individually for each option, with qualitative analysis and interpretation of quantitative results. Summary tables reporting the modelling results for all options are included in section 6.1.6.

6.1.1.2.Modelling and use of studies

For most of the quantitative analysis, the METIS[239] modelling software was used to underpin the findings on the impact of the different options. METIS is a modular energy modelling software covering with high granularity (geographical, time) the whole European power system and markets. Simulations adopted a Member State-level spatial granularity and an hourly temporal resolution for year 2030 (8760 consecutive time-steps per year), capturing also the uncertainty related to demand and RES E power generation.

For consistency with all parallel European Commission work on the 2030 Energy and Climate Framework, in the Red II, EE and Effort Sharing Regulation impact assessments, METIS was set-up (calibrated) such as to reflect as close as possible[240] the year 2030 projection of the power sector in the PRIMES EUCO27 scenario. The PRIMES EUCO27 scenario[241], built on the EU Reference Scenario 2016, ensures a cost-efficient achievement of at least 40% GHG reduction (including agreed split of reductions between ETS and non-ETS), 27% RES and 27% EE target.

A stand-alone analysis of the impact of potential policies promoting downstream price and incentive based demand response, at all customer segments (industrial, commercial, residential), has also been undertaken (detailed information hereon can be found in Annex 3.1). The options analysed looked at how to reach the full potential of demand response in order to reduce overall system costs, considering (i) both price and incentive based demand response, and their combination, as well as (ii) the level of access of demand service providers to the market (access rules and incentives), and (iii) customers' ability to react (by means of access to required technologies-smart metering, tariff structures and knowledge) for engaging in price based demand response. The analysis focused on the assessment of the theoretical potential of demand response, based on the nature of the electricity use/ability to shift demand by different clusters of consumers, its current level, and how the different options are likely to increase the share of the theoretical potential being realised, as well as in the estimation of associated cost and benefits.

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239 A detailed description of the METIS model can be found in Annex IV, including details on the implemented modelling methodology.

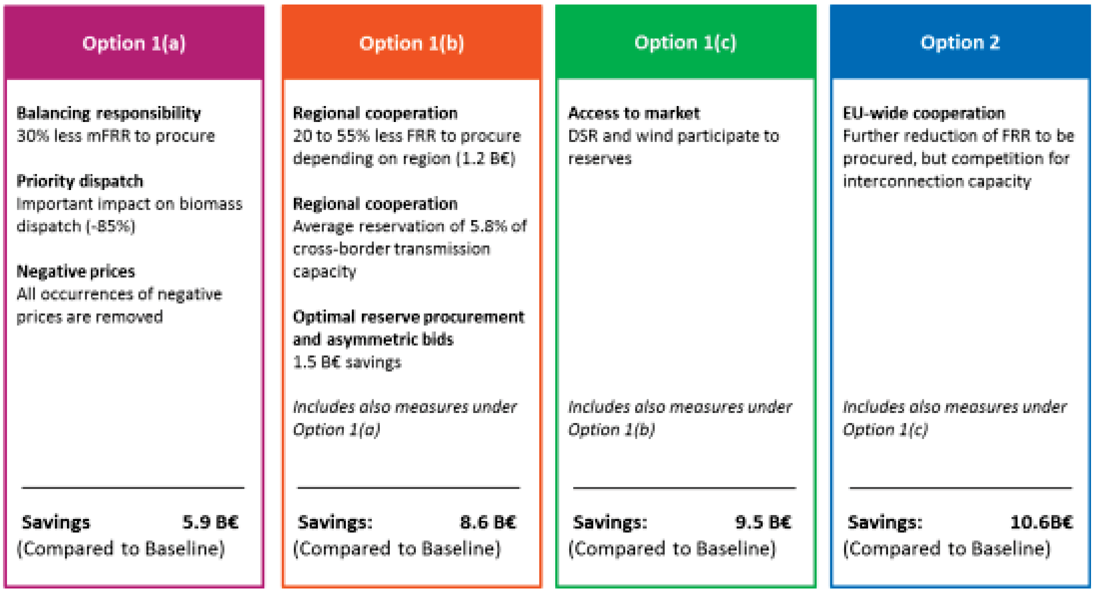
240 A detailed description of the METIS calibration to PRIMES EUCO27 can be found in Annex IV.

241 More details on the methodological approach followed concerning the baseline, on EUCO27, as well as on the coherence with the scenarios of all parallel initiatives can be found in Annex IV.

6.1.1.3.Summary of Main Impacts

Figure 8 below summarizes the annual quantified benefits of the assessed options for 2030[242], as presented in detail in sections 6.1.2 to 6.1.5. It illustrates the significant benefits of the measures under Options 1 to adapt the market design, with annual savings in 2030 of EUR 5.9 billion only for Sub-option 1(a) (level playing field), EUR 8.6 billion for 1(b) (strengthening short-term markets) and EUR 9.5 billion for Sub-option 1(c) (demand response/distributed resources). For Option 2 (fully integrated market) the calculated benefits would amount to EUR 10.6 billion.

Figure 8: Annual cost savings for Problem Area I in 2030 by option



Source: METIS

6.1.1.4.Overview of Baseline[243] (Current Market Arrangements)[244]

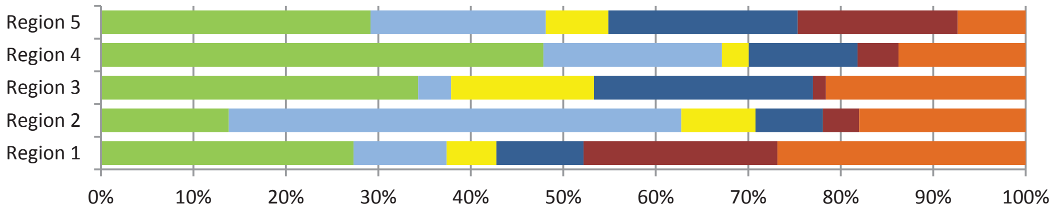
Under the baseline, the power system in 2030 relies heavily for energy on RES E generators, as well as conventional generation which is to a large degree inflexible. In particular, the share of RES E in electricity generation has almost reached 50%, thus being equal to the share of all other conventional generation together (i.e. gas, coal, lignite, nuclear, oil). The share of variable generation (solar and wind) in total generation approaches 30% across Europe. Concerning conventional generation, nuclear holds a 22% share, coal and lignite a 15% share, and natural gas 13%. The respective shares tend to differentiate across EU regions, based on the particularities of each region (Figure 9).

[242] All impacts were assessed for one full year (8760 hours) reflecting projected situation in 2030. Reported figures are in annual real terms (€'13).

[243] The assumptions concerning the baseline can be found in Section 5.1.2 and in Annex IV.

[244] Although all modelling work was based on the PRIMES EUCO27, the PRIMES scenario has as a basic assumption the existence of well-functioning competitive markets. As this is the ultimate goal of the assessed measures, the baseline departs form EUCO27, reflecting the observed distortions or inefficiencies of current market arrangements.

Figure 9: Shares of Electricity Generation per Region[245] in EU in the Baseline



	Region 1	Region 2	Region 3	Region 4	Region 5
Variable RES Generation	27%	14%	34%	48%	29%
Hydro	10%	49%	4%	19%	19%
Biomass, Waste & Other RES	5%	8%	15%	3%	7%
Gas	9%	7%	24%	12%	20%
Oil	0%	0%	0%	0%	0%
Solids	21%	4%	1%	4%	17%
Nuclear	27%	18%	22%	14%	7%

Source: METIS

A number of rules affecting dispatch remain in place, most notably priority dispatch[246] for RES E and that certain technologies are considered as must-run[247], reflecting current practices and nominations in the market. In fact special dispatch rules concern 60% of total installed capacity (752 GW on a total of 1,247 GW).

245 For the modelling purposes, an indicative split of Europe into five regions was made as follows (Cyprus was excluded as assumed not directly interconnected to the rest countries):

Region 1 (CE): Austria, Belgium, Czech Republic, Demark, France, Germany, Hungary, Luxembourg, Netherlands, Poland, Slovakia, Slovenia

Region 2 (NEE): Estonia, Finland, Latvia, Lithuania, Sweden and Norway.

Region 3 (NWE): Ireland and UK

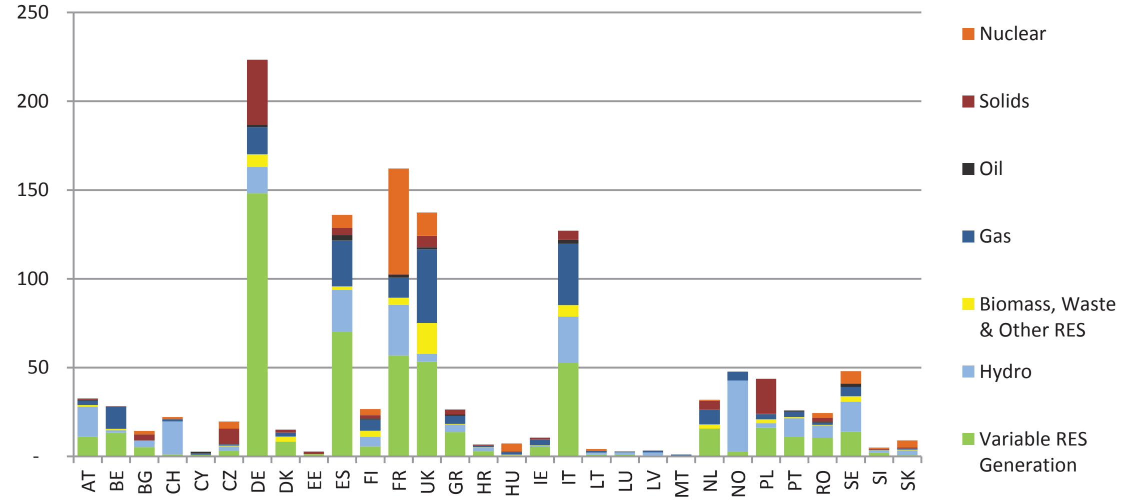
Region 4 (SWE): Portugal and Spain

Region 5 (SEE): Bulgaria, Croatia, Cyprus, Greece, Italy, Malta, and Romania

246 In "*Evaluating the impacts of priority dispatch in the European electricity market*", Oggioni et al (2014), show using a stylized model that significant increase of wind penetration under priority dispatch can cause even the collapse of the EU Target Mode. Test-runs performed using METIS came to a similar conclusion. Initial runs lead to significant hours of loss of load for many MS. In order to resolve this issue a "softened" definition for priority dispatch was assumed for the modelling, allowing the curtailment of units (which should not be normally the case under priority dispatch) but at a cost.

247 In general, when scheduled in day ahead, must-run units cannot be decommitted during intraday and are required to operate at least at their technical minimum level. For the scope of the modelling, coal and lignite units were assumed as being must-run in the baseline. Day-ahead scheduling was assumed though always optimal (so only units with priority dispatch were assumed to disrupt the economic merit order in day-ahead, namely biomass) for each national market, which may not be true in practice due to nominations, scheduling practices, etc. Modelling performed with PRIMES/IEM, results presented in Section 6.2.6.1, captured also the effect of nominations and other practices in the baseline.

Figure 10: Projected Generation Capacity in 2030 per Member State in GW[248]



Source: METIS

Another factor reducing the flexibility of the European power system is the limited allocation of interconnection capacity during intraday and balancing time frames, as well as the varying gate closures and products, which in practice reduce the opportunities for trading in the short-term markets and thus their liquidity.

Reserves are procured on a national level and in many cases in infrequent intervals[249], with corresponding services mainly provided by (large) thermal generators and only in some Member States by industrial consumers.

Demand response, storage (excl. hydro) and distributed generation have very limited participation in the market. In most cases available products are not customized for these resources, minimum thresholds exist for participating in the market, etc. At the same time, a large part of the generation, mainly RES E, are not balance responsible and do not have a strong incentive to perform accurate forecasts and declare accurate schedules in the day-ahead market (the share of variable generation is about 42% of total generation capacity). As a consequence, the observed imbalances are large, leading to increased needs for frequency reserves.

The deficiencies of the current regulatory framework create significant inflexibility to the system operation; the inflexibility in turn increases further the need for reserves (notably so-

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[248] Please note that the assumed generation capacities in the baseline have certain differences compared to the ones in EUCO27 PRIMES scenario, as a preliminary version of EUCO27 was used for the calibration. Further details can be found in Annex IV.

[249] For the scope of the modelling, a yearly procurement by (large) thermal generators and hydro has been assumed for countries with no reserve market, while daily optimal procurement is modelled in countries with such markets. More details can be found in Annex IV and in *"Electricity Market Functioning: Current Distortions, and How to Model Their Removal"* COWI (2016).

called replacement reserves)[250]. Close to real-time, the TSOs can mainly rely either on units providing replacement reserves or on very flexible (and expensive) units to avoid loss of load (peakers). In this context, in METIS replacement reserves provide than 600 GWh of electricity in the baseline, mainly in Poland and South East Europe. The same applies for RES E curtailment, as curtailment is the only alternative to the encountered stress of the system and the lack of available flexible resources: 13.0 TWh of RES E is found to be curtailed on an annual basis, mainly in the Iberian Peninsula (8.3 TWh) and UK/Ireland (4.1 TWh).

6.1.2. Policy Sub-option 1(a) (Level playing field amongst participants and resources)

6.1.2.1.Economic impacts

The restoration of the economic merit order curve in the wholesale electricity market has a direct and **significant positive impact** to the cost-efficient operation of the power system, leading to tangible reductions of the costs consumers. It would also allow to feed in (and remunerate from the market) more RES E (notably from wind and solar) to the system.

With special rules concerning unit dispatching eliminated (i.e. must-runs, priority dispatch), the TSOs are able to schedule and re-dispatch units more efficiently. As a result (in conjunction with the other measures under this option):

- total costs of the power system are reduced by 7%;
- the activation of replacement reserves is reduced by about 500 GWh;
- RES E curtailments (e.g. wind and solar) decline by 4.7 TWh[251]; and,
- the occurrence of negative prices is completely eliminated[252].

Figure 11 - which presents the merit order[253] at a given hour - illustrates how preferential dispatch rules for certain technologies shift the merit order to the right, resulting in price decreases but at the same time in an increase of the overall costs for the system. The example shown for biomass priority dispatch is also applicable for must-runs and priority dispatch of other (expensive) technologies. Restoring the economic merit order thus reduces the overall costs for the power system at times where these technologies would be out-of-the-money, while increasing the electricity price during these hours.

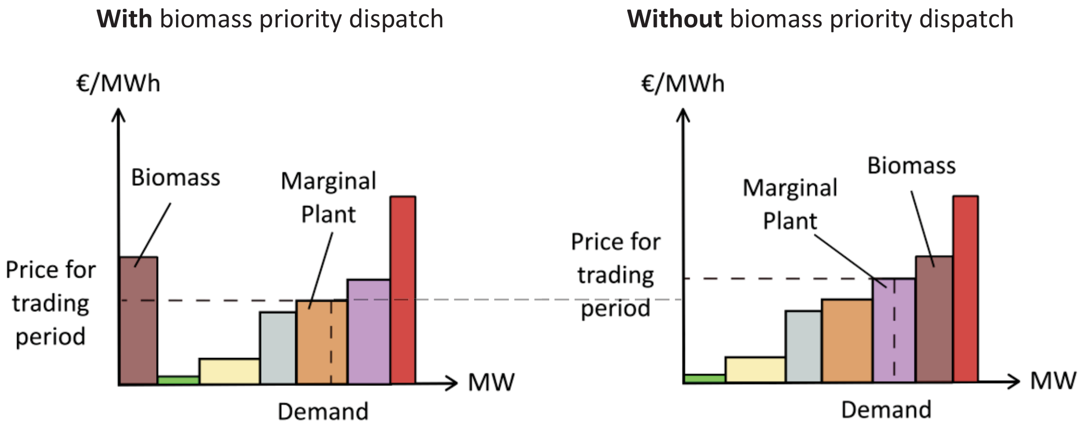
[250] It should be emphasized that METIS does not include a grid model. Thus the main use of replacement reserves ('RR'), to address grid (non-frequency related) issues, is not captured. The implemented methodology can only be considered as a proxy in an effort to capture a part of the impacts of RR. As some of the scenarios (Options 0 (baseline) and 1(a)(level playing field)) were characterised by important values of Loss of Load during the intraday time frame, it was assumed that this was addressed by replacement reserves. To compute the costs related to RR, first the intraday loss of load curve was identified at country level and then the amount of peaker capacity needed to bring the Loss of Load duration down to 3 hours in each country was computed. A cost of 60k EUR/MW/y for peaker units and fuel costs of 180 EUR/MWh was assumed.

[251] From a system perspective, it can sometimes be economical to reduce the generation of wind and solar in order to maintain the system balance.

[252] This result is directly linked with the modelling assumption that all electricity is traded in the market.

[253] Each generation fleet is represented as a block, as large as its power capacity and as high as its generation cost. Without distortions, the market dispatches the lowest (cheapest) blocks until demand is met. The generation cost of the most expensive dispatched power plant sets the clearing price.

Figure 11: Merit order effect of priority dispatch



Source: METIS

Focusing on priority dispatch, which was found to be the main distortion for the day-ahead market scheduling for the modelling[254], the biggest impacts on generation would be observed in Denmark, UK and Finland, where biomass holds a large share of generation capacity. The removal of priority of dispatch would have a considerable effect on expensive biomass production[255], which in most cases is dispatched out of the merit order. It can also be expected that the share of CHP generation would be negatively affected, due to the relatively inflexible character of CHP production[256]. On the other hand, removing priority dispatch rules would benefit variable RES E which could expand its production (due to the reduction in curtailments). More importantly, variable RES E producers could significantly increase their revenues due to the increase of the wholesale prices (partly due to the elimination of negative prices)[257]. Overall, the removal of priority dispatch and must-runs helps better integrating variable RES E generation and leads to significant system costs reductions and thus cost savings for consumers.

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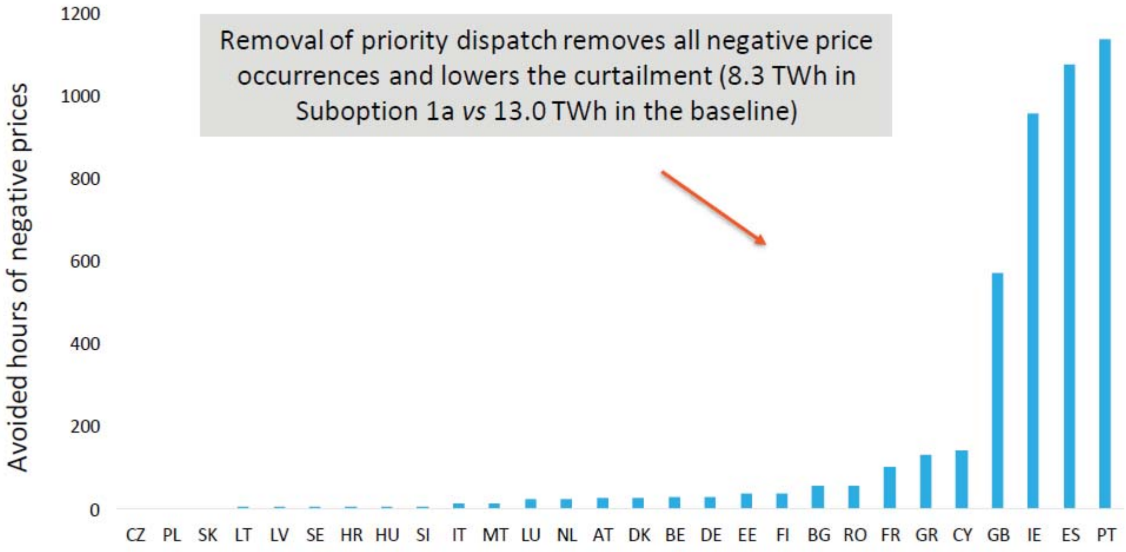
[254] Data availability on must-runs, nominations and other practices affecting the day-ahead schedule, leading to an operation of the system deviating from the economic merit order, was very limited and thus were not captured by the model. The impacts of must-runs were captured however for the intraday market and amounted to around EUR 0.5 billion.

[255] The Commission's study indicates that up to 85% of biomass generation could be affected by removing priority dispatch. This result is also partly due to the assumption of having only one fuel for biofuel/biogas, this being exclusively wood, rendering biomass very expensive. Note also that the analysis focuses on electricity dispatch and does not examine why would a biomass (or any other) plant want to operate with losses in the wholesale market (most likely an additional revenue stream like income from selling heat or some kind of operational support would be required), as is often the case today. A more complete analysis of this result is presented under environmental impacts, Section 6.1.6.

[256] As part of the limitations of the modelling, one should note that the effects of removing priority dispatch from CHP are not captured in the assessment. In particular CHP and small scale RES E are not modelled as separate assets. It can be expected though that the results on biomass would be applicable also to a large part of the CHP generation, unless they are able to recover their losses from the heat market or are industrial CHP, in which case industrial opportunity costs need to be considered.

[257] Because of biomass' assumed flexibility, a part of the lost revenues is recovered from its participation in reserve procurement and balancing energy activation

Figure 12: Effect of removal of special dispatch rules to negative prices



Source: METIS

The above also leads to an increase of the share of Combined Cycle Gas Turbines ('CCGTs') in power generation[258]. RES E generation enters the market merit order, thus catering for more efficient price formation in the day-ahead and intraday markets. The removal of priority dispatch will offer access on equal terms to all resources. Moreover, it will more than double the competitive segment of the market, which in the baseline was only 40% of the market.

As more resources participate under the same competitive rules in the markets, markets would become more competitive[259]. This implies an increase in wholesale prices as they will now reflect the actual marginal cost of generation instead of one technically lowered via rules affecting dispatch[260]. As a result, this will lead to a much more cost-efficient operation of the power system, and consequently to a 7% decrease of its total cost.

Finally, the extension of balance responsibility to all generating and consuming entities, offers a strong incentive for variable RES E and other balance responsible parties to improve their forecasting, bid more accurately in the day-ahead market and be more active in the intraday markets. This leads to smaller imbalances and a lower requirement for reserve procurement by the TSOs. In particular the needs for mFRR are reduced by around 30%. This, combined

[258] Share of CCGT in total net electricity generation increases from 12.3% to 15.1%.
[259] See for a more detailed discussion of the arguments for and against maintaining priority dispatch in Annex 1.
[260] The elimination of the significant hours with negative prices also contributes to the increase of the average wholesale price.

with the capability of the demand response to also participate[261] in the reserve procurement and balancing markets, leads to a more cost-efficient reserve procurement process.

6.1.2.2.Who would be affected and how

Abolishing priority dispatch and priority access would mainly affect RES E producers using biofuels and CHP[262] and operators that benefit from priority dispatch when producing using indigenous resources fuels (if their marginal costs are substantial). For low marginal cost, variable generators, such as wind and solar power plants, the impact is actually positive, which will be amplified by measures to enable RES E access to ancillary services markets.

In any event, all generators will benefit from increased transparency and legal certainty on redispatch and curtailment rules. For TSOs, the removal of priority dispatch and priority access would also facilitate grid operation.

Introducing balancing responsibilities (with exemption possibilities for emerging technologies[263] and or small installations[264]) will mainly impact generators currently exempted or partly shielded from balancing responsibility. Accordingly, this measure will mean they have to increase their efforts to remain in balance (e.g. through better use of weather forecasts) though at the costs of being exposed to financial risks.

6.1.2.3.Administrative impact on businesses and public authorities

The removal of priority dispatch, priority access and ensuring compliance with the balancing rules would give rise to administrative impacts for RES E (and CHP) generators, in particular for operators of very small installations. This administrative impact can however be significantly reduced by facilitating aggregation, allowing the joint operation and management of a large number of small plants (as discussed in more detail under Option 1(c)).

6.1.3. Impacts of Policy Sub-option 1(b) (Strengthening short-term markets)

6.1.3.1.Economic Impacts

Strengthening short-term electricity markets improves market coupling across time-frames, leads to a more efficient utilization of interconnector capacity and reduces the amount of required reserves, as well as their cost.

261 Note though that as no measures are assumed to be implemented here for incentivizing the wider participation of demand response, only industrial consumers are assumed to be participating in the respective markets.

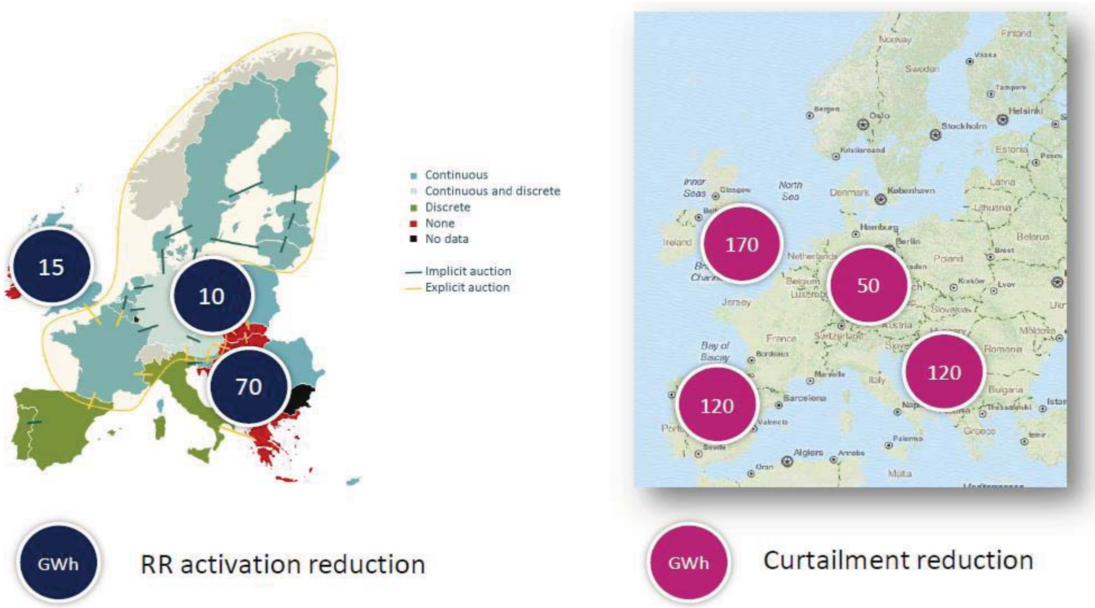
262 As part of the limitations of the modelling, one should note that the effects of removing priority dispatch from CHP are not captured in the assessment. See also footnote 254.

263 In the PRIMES EUCO27 scenario, the emerging technologies of tidal and solar thermal generation (other technologies having insignificant shares) are projected to have a total installed capacity of 7.26 GW (0.7% of total generation capacity) and produce 10 TWh of electricity in 2030 (0.3% of total generation).These shares only slightly increase by 2050.

264 In the PRIMES EUCO27 scenario, RES E small-scale capacity is projected in 2030 to reach 85 GW (7.8 % share in generation capacity) and produce 96 TWh of energy (2.9% share of total generation).

The efficiency of the intraday markets is improved due to the harmonization of their market specifications, including the transition to continuous trade and harmonisation of gate closures, as well as by an improved allocation of interconnector capacity across time-frames. Harmonising intraday markets across Europe[265] allows to further reduce RES E curtailment by 460 GWh and the utilisation of replacement reserves by 100 GWh. Note that curtailment is not only reduced in countries where implicit auctions were not implemented in Option 1(a) (level playing field), but in already implicitly coupled regions too. Thus, extending the coupled area also benefits already coupled countries such as Germany, since it can export more of its variable RES generation. The effects are illustrated in Figure 13.

Figure 13: Positive impacts of harmonising intraday markets across Europe[266]



Source: METIS

By improving the methodologies for reserve dimensioning and procurement of balancing reserves, the need for balancing reserves is further reduced compared to Option 1(a). Certain improvement comes from the separation of the bids and prices for up and down regulation in order to reflect their true underlying marginal costs, which may be different both for generation and load[267]. The separate provision of downwards reserves greatly improves the efficiency of the system, as now thermal plants are not forced to be online to provide such reserves. Another means is via the procurement of reserves on a day-ahead basis, thus their sizing being able to reflect the hourly needs for these services, while at the same time allowing the most efficient resources at a given hour to be procured as reserves by the TSO.

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[265] Continuous trading was modelled as consecutive hourly implicit auctions.

[266] The figures presented in this paragraph show the impact of implicit intraday auctions only. Other measures of Option 1(b) (strengthening short-term markets), in particular interconnection reservation at day-ahead for reserve procurement, tend to increase intraday costs.

[267] Although the separation of upward and downward balancing was initially foreseen for this initiative, and thus assessed herein, it may be introduced earlier in the EB GL.

The reduction in the reserve needs though is mainly achieved by the regional reserve dimensioning and more efficient exchange and sharing of balancing capacity among TSOs, as the generation and consumption patterns differs between Member States according to the generation mix, renewable energy sources and differences in energy consumption. Thus, the 79.6 GW of reserve needs (FCR + FRR) in Option 0, is reduced to 65.8 GW in Option 1(a) (level playing field) and to only 42.3 GW in Option 1(b) (strengthening short-term markets) (a reduction of 47% compared to the baseline).

It is important to note that the reduction in FRR[268] is stronger in the well-interconnected regions (about 50% reduction), namely Central Europe, the Nordics and South / South East Europe, while the benefits for UK/Ireland and Spain/Portugal are smaller due to their limited interconnection (about 20% reduction). In order to achieve these reductions from the sharing of reserves, the Member States need to ensure that sufficient interconnection capacity is reserved for this purpose, in order to ensure that despite the lower reserve requirements, the national ability to balance the system remains the same[269]. The amount of capacity that needs to be reserved for this purpose is on average approximately 6%[270] of the Net Transfer Capacities ('NTCs'), with actual values varying significantly per interconnector and per hour of the day.

Similarly, different market areas have different access to flexible resources and such flexible resources are vital to the cost-efficient integration of renewable electricity generation. TSOs may not only procure smaller volumes of reserves but providers of relatively cheap flexibility resources may supply a larger volume thereof. Hence, overall balancing market payments are reduced, while at the same time more interconnection capacity can be given to the market by reducing transmission reliability margins ('TRMs').

An interesting observation coming from the assessment is the increased generation by baseload thermal plants, compared to more flexible thermal plants. In particular, the electricity generation of nuclear, CCGTs, coal and lignite plants increases by 10%, while the generation of gas and oil peakers reduces by 50% compared to the baseline[271]. The reason is that by sharing resources between countries and decreasing reserve needs, the baseload plants

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[268] Both mFRR and aFRR

[269] Adopting a regional approach to reserve dimensioning results in lower reserve requirements because of the statistical cancellation that can occur between imbalances originating from different countries. As a result the reserve needs are lower when adopting a regional dimensioning approach. The regional reserve need is then translated into minimal reserve requirements at national level by using an allocation criteria (in METIS case the national annual demand). However a national TSO still has to face the same level of risk - the imbalances on its Control Area remain the same – and the minimal reserve requirements may not be sufficient to balance its system. As a consequence, national TSOs have to reserve a share of the interconnection capacity for reserves, so that the other countries can assist it to balance the system. METIS does not explicitly model reserve exchanges, but risk pooling.

[270] Considering that for Option 1(b) an assumption was made that the NTC capacities were increased by 5%, reflecting e.g. the reduced TRM compared to Option 1(a) due to the increased co-operation between MS via ROCs, it is interesting to notice that the average capacity that needs to be reserved for sharing balancing reserves is around the same level. On the other hand this does not signify something, as the averaging hides the huge variability among hours and interconnectors.

[271] It should be noted that the analysis excludes the effect that increased generation by thermal plants would have on the carbon market and how this in turn would indirectly impact electricity generation.

do not need to retain part of their capacity on stand-by for supplying reserves and thus can increase the quantities of energy they generate. At the same time, though, flexible plants end up competing for reduced amounts of reserve needs, thus their revenues are significantly reduced compared to Option 0 (baseline) and Option 1(a) (level playing field)/ Therefore, better interconnecting markets and making them more flexible serves as a second option for bringing more flexibility into the system, complementary to but also competing with flexible generation plants.

Enhancing TSO regional coordination through the establishment of regional operational centres and by optimising market, operational, risk preparedness and network functions from the national to the regional level will entail significant efficiency gains and increase social welfare.[272] For example, the regional sizing and procurement of reserves via ROCs could lead to benefits of EUR 3.4 billion compared to benefits of EUR 1.8 billion from national sizing and procurement of reserves based on daily probabilistic methodologies.[273] Significant welfare benefits would, *inter alia*, derive from the more efficient use of infrastructure and from a decrease of financial losses that would otherwise result from the disconnection of demand in case of generation shortages.

6.1.3.2.Who would be affected and how

Improving short-term markets will affect all generation operators to a certain extent but it will in particular improve the ability of **variable RES E operators** to participate in the market.

Improving intraday and balancing markets would impact the work of the **TSOs** and **Power Exchanges**, because of their involvement in the operation of these markets. On the one hand this will require operating the system and organising trade within shorter timeframes. On the other hand, the shorter timeframe will allow TSOs to benefit from significant efficiencies and to reduce the risk of system problems. **TSO**s will also be affected through the need to collaborate closer with neighbouring TSOs through ROCs and through the changes to the balancing markets which they operate. This has the positive effect of requiring TSOs to consider systematically the impact of their actions on their neighbouring TSOs.

6.1.3.3.Administrative impact on businesses and public authorities

The administrative impact on **businesses** is marginal as compared with the baseline.

Power exchanges and **TSO**s would have to review and adapt their business practises to facilitate the changes to the market functioning as envisaged under this option. Notably, changes will have to be made to trading arrangements for intraday and balancing products. TSOs would collaborate through ROCs, which will have to be set up. The setting up of the

[272] For more information on the assessment of the economic impact of ROCs, please refer to Table 2 of Annex 2.3 of the Annexes to the Impact Assessment.

[273] "*Integration of electricity balancing markets and regional procurement of balancing reserves*", COWI (2016).

ROCs can be estimated to cost between 9.9 and 35.6 million Euros per entity, depending on the functions and degree of responsibilities attributed to the ROCs.[274]

Whereas these costs are not insignificant, these costs of several million Euros (which would be covered and compensated by grid fees) are minor when compared with the benefits this option will bring.

6.1.4. Impacts of Policy Sub-option 1(c) (Pulling demand response and distributed resources into the market)

6.1.4.1.Economic Impacts

The series of measures assumed in this Option include (i) the adaptation of balancing products closer to what distributed resources like demand response, variable RES and small scale storage can provide, (ii) the facilitation of the participation of distributed resources in the market mainly via aggregators and (iii) stronger incentives for the roll-out of smart-meters. These measures significantly improve the efficiency of the market and the reduce costs.

The market set-up under Option 1(c) provides the opportunity to variable RES E to better manage their imbalances due to forecast errors at lower cost (due to more competitive prices), but also to receive additional revenues for any flexibility they can provide to the market. Similarly, demand is offered the incentives and capability to respond to market prices and thus complete existing electricity markets. This can be achieved by either shifting load from hours of peak demand to hours with low demand (e.g. via storage or changing consumption partterns) or by simply adjusting consumption (when load cannot be shifted or is not really needed) [275].

Available data coming from a standalone analysis[276] performed on the impact of potential policies promoting downstream price- and incentive-based demand response, at all customer segments (industrial, commercial, residential), show that demand response can be of great service, and deliver net benefits to the system as a whole while engaging all consumer segments. More in particular, it has been demonstrated that demand response schemes can lead to a reduction of the peak demand and thereby of the required backup capacity in both the transmission and distribution networks. This also translates into lower investment needs.

The analysis has shown that in a business as usual scenario (reflected in Option 0) demand response can account for approximately 34 GW, of which 19 GW will come from incentive and 15GW from price based demand response. With a supporting policy framework in place, as in Option 1(c), demand response can account for approximately 57 GW in 2030, of which 39 GW will come from incentive and 18 GW from price based demand response.

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[274] "*Integration of electricity balancing markets and regional procurement of balancing reserves*", COWI (2016).

[275] As part of the limitations of the modelling approach, these benefits were not fully assessed because of data unavailability. Therefore the same load profile was used, based on the ENTSO-E's TYNDP assumptions, without being known at which extent it already included some DR (at least for EV charging)

[276] See Annex 3.1 and "*Impact Assessment support Study on downstream flexibility, demand response and smart metering*", COWI (2016).

Allowing small-scale producers, storage and consumers to participate in the market, e.g., through aggregated bids, creates incentives for demand side response and flexible solutions, pulls the above potential in the market and creates a more dynamic market. New flexible resources are made available for reserve procurement and balancing market. These resources bring significant short-term and mid-term flexibility[277] to the system, contributing to the more efficient handling of scarcity situations and integrating variable RES E. This abundance of available resources significantly reduces the cost of the power system and, most importantly, the load payments to EUR 253 billion, from EUR 278 billion in the baseline and EUR 293 billion in Option 1(a).

These reported savings[278] are mainly a result of a significant shift in the provision of reserves from thermal plants to demand side response (incl. storage) and wind. For example, while in Option 1(b) (strengthening short-term markets), gas was providing about 20 GW of reserves, hydro 19 GW and coal 3 GW, under Option 1(c) demand response partly replaces the above plants by providing 5 GW of reserves. In particular demand response and small scale storage (electric vehicles and heating storage) become the main providers of upward synchronized reserves, providing 33% of corresponding needs[279]. Wind provides an additional 90 MW of upwards synchronized reserves and 330 MW of downward synchronized reserves.

6.1.4.2.Who would be affected and how

The new provisions opening up the markets to aggregated loads and demand response will bring business opportunities for aggregators, new energy service providers, and suppliers who choose to expand their portfolio of services, but will also affect generators who are likely to face reduced turnover from lower peak prices and from providing reserves.

Furthermore, demand side flexibility, along with access to real time data coming from smart metering, will help the network operators optimise their network investments and cost-effectively manage their systems. In the case of TSOs, it also allows for the better calculation of settlements and balancing penalties based on real consumption data. On the other hand, suppliers may face higher imbalances and resulting penalties as their customers change consumption patterns.

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[277] For more details on the flexibility needs of the system and how storage, interconnections and demand response can answer such needs please see "*METIS Study S7: The role and need of flexibility in 2030. Focus on Energy Storage"*, Artelys (2016).

[278] The proposed measures are expected to also have an impact on the day-ahead market, but as explained in Annex IV this was not possible to assess due to the lack of sufficient detailed data. Benefits from load shifting or load reductions were not assessed with METIS due to the lack of a dynamic profile for demand and storage, which would better capture the reactions of demand to market prices. These impacts were captured though with PRIMES/IEM, results presented in Section 6.2.6.1. The benefits of demand response and its full potential is analysed in more detail in Annex 3.

[279] The analysis shows the demand response does not provide any downwards balancing at all (by increasing demand when needed), as this is provided at a much lower cost by RES and conventional generation (by decreasing generation and saving fuel costs). This result is subject to the limitations of the modelling that does not use dynamic load profiles for demand and storage. Therefore the relevant benefits are most likely underestimated in the assessment.

Finally, end consumers are expected to benefit from more competition, access to wider choice, and the possibility to actively engage in price based and incentive based demand response, and hence from reduced energy bills. Even those end users who choose not to participate in demand response schemes could still profit from lower wholesale prices that result from demand response, assuming that the respective price reductions are passed on to consumers.

Box 6: The possibility of large-scale grid disconnection

Looking forward, our modelling (the EUCO27 scenario) shows a continuation of the general trend of rising retail electricity prices through to 2030, stabilising from 2035 onwards. Given the decreasing costs of small-scale renewable generation and storage technologies, concerns have been raised that this trend could result in a growing number of prosumers becoming self-sustainable and disconnecting from the electricity network – a development that could have several consequences.

On the one hand, this potential 'flight from the grid' could see the remaining connected ratepayers bear an increasing share of the burden of contributing to public finances and financing the electricity network. On the other, grid costs may actually fall as distributed generation and storage assets enable network operators to more efficiently manage the grid and connect remote customers.

Predicting the full extent and implications of this trend is difficult given the current uncertainties, including regarding future cost reductions in small scale renewables and storage technologies, and the lack of real-world case studies. Nevertheless, our analysis suggests that this development will be progressive, and that the risks of large scale disconnections are limited given the difficulties of achieving complete self-sufficiency throughout the year.

In particular, even if decentralised generation and storage becomes competitive, it is questionable whether self-sufficient prosumers will fully disconnect from the grid. Disconnecting would imply losing the grid as back-up for when their own generation is inadequate (e.g. for sustained periods of low sunlight). It would also mean that prosumers forego the opportunity to sell excess electricity to the market (e.g. during prolonged sunny periods when their installed storage is at full capacity). This is one of the reasons why the MDI aims at ensuring full access of prosumers to electricity markets.

It should be added that the discussion of disruptive large scale disconnections is not only connected with distributed resources but to the perception that consumers are increasingly confronted with perverse incentives and hidden subsidies. To address this, the initiative includes measures that should lead to more cost-reflective distribution tariffs i.e. tariffs that allocate the costs of the grid fairly amongst system users. Cost-reflective tariffs will send the right long-term economic signals to system users and allow a market-driven move towards a more efficient electricity system, which will contribute to limiting network tariffs and lead to investments that are economically rational and efficient.

What is certain is that public authorities and network operators will have to adapt in order to effectively manage the challenges of any transition towards a more decentralized electricity system, and make the most of the opportunities this presents. Completely self-sufficient consumers who do not wish to be connected to the grid should not contribute to the grid costs.

6.1.4.3.Impact on businesses and public authorities

The measures proposed to enable the uptake of demand response are designed to reduce market barriers for new entrants and provide them with a stable operating framework. This is particularly important for start-ups and small and medium-sized enterprises ('**SME**s') who typically offer innovative energy services and products. However, these measures may introduce an additional administrative impact for Member States and their competent authorities that will be required to clearly define in such a new setting: (i) roles and responsibilities of aggregators, as well as (ii) arrangements for consumers' entitlement to participate in price based demand response schemes, including their access to the enabling smart metering infrastructure. At the same time, access to smart metering will support consumer engagement, with better informed and more selective consumers also making it easier for NRAs to ensure proper functioning of the national (retail) energy markets[280].

Moreover, thanks to the wider deployment of smart metering, the distribution system operators will be in a position to lighten, and improve, some of their administrative processes (linked to meter reading, billing, dis/re-connection, switching, identification of system problems, commercial losses), and offer increased customer services[281]. Similarly, transmission system operators will optimise their settlement and balancing penalty calculations, as they can make use of real time data coming from smart metering[282].

6.1.5. Impacts of Policy Option 2 (Fully integrated EU market)

6.1.5.1.Economic Impacts

By creating a centralised, fully integrated European market with market design features and procedures in place in order to deal with grid constraints and increase the available interconnection capacity offered to the market (e.g. due to the further reduction of security margins and the implementation of flow based market coupling across time-frames), the European power system can be operated even more efficiently than in the options above.

Benefits coming from the further improvements in the dimensioning and procurement of balancing reserves, now on a European level, as well as the better utilization of interconnectors by the EU Independent System Operator, lead to further reductions of the

280 See Annex1(c).1, Stakeholders views; Reference CEER discussion paper *"Scoping of flexible response"*, 3 May 2016

281 "*Bringing intelligence to the grids – case studies*" (2013) Geode Report; http://www.geode-eu.org/uploads/REPORT%20CASE%20STUDIES.pdf; also "*Eurelectric policy statement on smart meters*" (2010); http://www.eurelectric.org/media/44043/smart-metering-final-2010-030-0335-01-e.pdf

282 "*Towards smarter grids: developing TSO and DSO roles and interactions for the benefit of consumers*" (2015) ENTSO-E; https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/150303_ENTSO-E_Position_Paper_TSO-DSO_interaction.pdf; "*Market design for demand side response*" (2015) ENTSO-E Position paper; https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/entsoe_pp_dsr_web.pdf

total costs compared to Option 1(c) by 1.5%. Reserve needs are further reduced by 30% compared to Option 1(c) and 63% compared to the baseline, although downwards reserves, which have a low procurement cost, are mainly procured on a national level, in order to use interconnectors mainly for exchanging electricity instead of reserving it for potential assistance to/from the neighbours.

The results indicate that although the economic benefits of moving from a national to a regional approach (Option 1(b) (strengthening short-term markets)) are significant, the move towards a more integrated European approach (Option 2) has a less significant economic value-added, as most of the benefits have already been harvested by moving towards a regional approach. On the other hand this result is also subject to the limitations of the modelling, not being able to capture the positive impacts from the more efficient operation of the network (since METIS does not include detailed network modelling).

6.1.5.2.Who would be affected and how

Under this option, TSOs, DSOs, power exchanges, electricity undertakings in general as well as Member States and competent authorities would be subject to far-reaching organisational changes (e.g. EU ISO and EU Regulator instead of national TSOs and regulators), and bound by fully harmonised rules setting out the full integration of the EU electricity market. This increases the likelihood that these rules may be difficult to implement in specific countries. This could lead to high resource requirements amongst these stakeholders, public authorities and Member States, that may be ultimately borne by consumers.

6.1.5.3.Impact on businesses and public authorities

The creation of a fully integrated European electricity market can be considered the most efficient of all the options and could, in the long run, avoid frictions from coordination and provide for a high quality electricity system with a high degree of security of supply. Under this option, it could be argued that in the long run the impact on stakeholders (e.g., TSOs, DSOs, power exchanges, electricity undertakings, etc.) may be reduced, since the integration of the electricity market would ensure a high degree of consistency.

However, this option would entail significant changes compared to the current state of the art of the electricity systems across the EU. It would be necessary to build new entities, processes and methods without being able to draw upon established practice (e.g., for the establishment of an EU ISO). Hence, there is a risk that this would lead to disruptions and would require a significant amount of time to become operational.

This option would also reduce the scope to take into account regional specificities and to draw upon established regional actors. This option would reduce the scope to develop rules at the regional level between the parties involved in organising the cross-border trade and system operation. This is because the key framework as well as the institutional structure would already be set out at the pan-European level.

In light of the above, it should be noted that the political and administrative effort required under this option would be considerable.

6.1.6. Environmental impacts of options related to Problem Area I

The measures proposed in this Problem Area aim to improve the cost-efficiency and the flexibility of the power system. By doing so, climate-friendly variable RES E can be better integrated in the market; resources are used more efficiently, and unnecessary fuel-based generation (e.g. backup generation needed because of missing rules for cross-border short-term markets) can be avoided by better using the aggregation potential of the internal market. Using the full potential of demand response has also a positive effect on the environment. If consumption can be shifted more easily to off-peak times, less backup generation from fuel-based plants is needed.

On the other hand, the removal of privileged rules for certain production forms may lead to a shift from some RES E production (i.e. biomass) to other generation types which will not only be wind and solar, but also fossil fuel-based. Therefore, although direct CO_2 emissions from the power sector decrease while moving from Option 1(a) to Option 1(c), from 615 Mt CO_2 to 600 Mt $C0_2$, METIS results show an increase when moving from the baseline to Option 1(a) by 60 Mt CO_2. The analysis of the impact on emissions is, however, complex[283].

The removal of priority dispatch from biomass (as well as from any other resource, including must-run generation) is pivotal in restoring the economic merit order in the power markets and significantly increasing their economic efficiency. Such a measure would discontinue the use of expensive biomass as baseload generation, replacing it by the marginal technologies (mainly coal and gas). Expensive biomass would then mainly be used in the power sector as a flexible generation technology, as well as for providing reserves.

The replacement of biomass by gas and coal could lead in the short-term to increasing emissions. The environmental impacts of the market design measures cannot though be examined in isolation from all other complementary energy and climate policies. At the EU level, the reduction in greenhouse gas emissions within the sectors covered by the EU ETS is guaranteed by the declining cap which in turn ensures that the emissions reductions objective is met cost-effectively. In the event of an increase in emissions from certain changes in the power sector mix, the corresponding increase in demand for allowances would raise the carbon price leading to an increase in abatement through other means, whether this is through a fuel switch in power generation elsewhere or an emissions reduction in other ETS sectors. Due to the binding limit on overall emissions a reduction in the use of biomass would therefore eventually result in the same amount of GHG emissions over time, with a different fuel mix at a lower total system cost.

The main effects of removing priority dispatch for biomass are therefore:

- only cheaper fractions of biomass are being used (such as waste streams), while the more expensive one is being used as flexible dispatchable generation, rather than subsidised baseload;

[283] It should be noted that the analysis excludes the effect that increased generation by thermal plants would have on the carbon market and how this in turn would indirectly impact electricity generation.

- overall higher CO_2 prices and lower generation costs, and higher wholesale electricity prices (but most likely lower retail prices, as no subsidies will need to be recuperated outside the wholesale market).
- more favourable conditions for gas, with more operating hours;

The possible increase in emissions in the power sector is in reality the effect of current energy policies for RES E (and specifically the incentives given by the subsidization of biomass) and not of electricity market related policies. By removing the distortions currently present in the electricity markets, the market is able to give clearer signals on the interactions between climate and energy policies and help identify the right balance between cost and resource efficiency and emissions reduction.

6.1.7. Summary of modelling results for Problem Area I

The analysis shows that although today electricity markets function much better than in the past, there are still significant gains to be harvested. Restoring the merit order and creating a level-playing field for all technologies can reduce the operational cost[284] from EUR 83.4 billion in Option 0 to EUR 77.5 billion in Option 1(a). Another EUR 2.7 billion can be saved by further strengthening and linking the short-term markets; EUR 0.9 billion by better integrating demand response and RES E into the market; and EUR 1.1 billion from fully integrating EU markets. Overall, the measures under Option 1(c) can lead to cost reductions up to 11.4% compared to the baseline, while the additional measures under Option 2 would raise this to 12.7%.

When considering the above results, three important points need to be made. First of all the cost saving estimates for each option are directly related to the volume of traded energy (and reserves) they concern. Option 1(a) (level playing field) affects all market frames, but most notably the day-ahead, where the largest volume of trades takes place. Options 1(b) (strengthening short-term markets) and Option 2 (fully integrated markets) focus on interconnections (for all market time frames), intraday and balancing; traded volumes there are only a fraction of the ones of the day-ahead. Option 1(c) (demand response/distributed resources) concerns mainly the balancing and reserve markets[285]. Secondly, the effect of the measures on the intraday and balancing traded volumes is much greater, but more difficult to quantify, as it is bi-directional (upwards and downwards compared to the day-ahead scheduled energy) and complementary to the day ahead market[286]. Finally the proposed

[284] Cost reflects the operational cost of the electricity system (reflecting mainly fuel cost and CO_2 cost). Lower cost implies a more efficient operation of the system.

[285] The proposed measures are expected to also have an impact on the day-ahead market, but this was not possible to assess due to the lack of sufficient detailed data. See also footnote 278.

[286] There are two important connections with the day-ahead market. The closer the day-ahead schedule matches the optimal dispatch (based on realized demand and generation), the smaller the need to act in the shorter term markets; and how interconnection is split between day-ahead and intraday. For this reason it is preferable to look at the results as a whole and not separately for each market frame.

blocks of measures were deemed as the most efficient ones, but also were found to have limited impact on the reported results[287].

Apart from the cost savings, which relate only to the generation side costs, it is important to also examine the final cost of the wholesale market for the consumers, referred to below as 'Load Payments' (see Glossary). With the removal of all special rules affecting dispatch, the wholesale price begins reflecting the actual marginal value of electricity and thus increases; this affects also the Load Payments which increase by 5%. Subsequent Options though bring more resources into the market, better utilizing the interconnections and further improving the cost-efficiency of the market, gradually reducing the Load payments by 6% in Option 1(b) (strengthening short-term markets), 9% for Option 1(c) (demand response/distributed resources) and 11.5% for Option 2 (fully integrated market) compared to the baseline. The above are equivalent to a reduction of the wholesale market cost for the consumer[288] from 78 EUR/MWh in the baseline to 71 EUR/MWh for Option 1(c) and 70 EUR/MWh for Option 2.

Table 10: Monetary Impacts (in billion EUR) of the assessed Options (for EU28+NO+CH in 2030)

Monetary Impacts (billion EUR)[289]					
	Option 0	**Option 1(a)**	**Option 1(b)**	**Option 1(c)**	**Option 2**
	Baseline	Level playing field	Strengthening short-term markets	Demand response/ distributed resources	Fully integrated markets
Cost day-ahead	82.5	76.9	73.5	72.7	72.4
Cost intraday	1.4	0.9	1.2	1.1	0.3
Cost balancing	-0.5	-0.3	0.1	0.1	0.1
upwards	0.7	0.5	0.7	0.7	0.7
downwards	-1.2	-0.8	-0.6	-0.6	-0.6
Total cost	83.4	77.5	74.8	73.9	72.8
Cost savings	**-**	**5.9**	**8.6**	**9.5**	**10.6**
Load Payments day-ahead	278	293	262	253	246
Load Payment Savings	**-**	**-15**	**16**	**25**	**32**

Source: METIS

[287] A sensitivity performed with METIS introducing the Option 1(c) measures (demand response/distributed resources) before Option 1(b) (strengthening short-term markets) shows a marginal improvement of Option 1(c) benefits by EUR 0.3 billion, despite the much higher potential for improvement still available in the market in the context of this Option.

[288] If these costs were shared equally among consumers.

[289] Unless otherwise noted, figures in all tables represent annual numbers for 2030. The geographical context is always noted in the title of each graph and in some cases it also covers NO and possibly CH because of the market coupling of EU Member States with these countries.

The monetary impacts described in Table 10 are very closely linked to the impacts of the measures on the wholesale prices. In Option 1(a) (level playing field) the increase of the competitive segment of the market from 40% (due to priority dispatch and must-runs) to 100% is the main driver for a more cost-efficient operation of the system, with no negative prices observed in the performed model runs, leading in the end to higher day-ahead prices. In parallel the reserve prices are generally lowered, due to the reduction of the inflexibility in the system. Only mFRR upwards prices increase, as these services are now primarily offered by peaking units.

In Options 1(b) (strengthening short-term markets) the trends reverse, as more resources enter the market, thus lowering day-ahead prices. The better utilized interconnection capacity and the improved functioning of the reserve markets allows baseload plants to produce more electricity in the day-ahead, while the more flexible (and expensive) plants become the main providers of reserves. As a consequence, balancing prices tend to increase (together with intraday prices). Subsequently, the introduction of demand response and the provision of reserves by RES E in Option 1(c) (pulling demand response and distributed resourced into the market) further lower wholesale prices (as more resources enter the market), with the exception of downwards reserve prices which increase[290]. Finally the impacts of Option 2 (fully integrated markets) are similar to the ones of Option 1(b) (strengthening short-term markets).

Table 11: Impacts (EUR/MWh) to Average Annual Wholesale Prices (for EU28 in 2030)

Average Wholesale Prices (EUR/MWh)					
	Option 0	**Option 1(a)**	**Option 1(b)**	**Option 1(c)**	**Option 2**
	Baseline	Level playing field	Strengthening short-term markets	Demand response/ distributed resources	Fully integrated markets
Day-ahead Market Price[291]	78.4	82.5	73.9	71.3	69.6
Balancing Price - aFRR upwards	71.9	58.3	76.2	71.3	72.3
Balancing Price - aFRR downwards	52.8	52.5	54.4	59.8	60.6
Balancing Price - mFRR upwards	72.1	82.3	85.6	76.3	76.3
Balancing Price - mFRR downwards	70.1	65.2	64.7	58.4	58.3

Source: METIS

An interesting aspect to examine is the distributional impact of the various options on the generator surplus (i.e. revenues above cost) and consumer surplus (i.e. cost below VoLL). It is important to note that this should not be interpreted as an investment or "missing money" analysis, since the modelling used here is static (based on the same set of capacities across the

[290] Downwards balancing activation is a benefit (fuel savings) for the system, while there is no gain (in METIS) to increase demand.

[291] EU weighted average price on Member States' demand

options). The issue of investments is analysed in Section 6.2.6.3, using a dynamic investment model (PRIMES/OM).

With the day-ahead prices significantly affected by the measures, so does generator surplus (i.e. revenues above cost). The distributional impacts on the market players though are concentrated on thermal generators, with competitive RES E generators even increasing their day-ahead revenues (not considering the additional revenues from the other markets).

Although in the baseline thermal generation seems to be making reasonable revenues, sufficient in many cases to cover fixed costs – especially for gas units – the improvements in the market design introduced in Options 1(b) (strengthening short-term markets), 1(c) (demand response/distributed resources) and 2 (fully integrated markets) lead to a significant decrease of their revenues, turning their operation to loss-making. Note, this result is a large extent due to the static modelling approach followed here and the increased competition in the market, as a result of bringing more resources into it and better utilising interconnections (thus better sharing national resources across EU). With the power generation capacities remaining constant across Options, this leads to a market with increasing resources participating (to the point of oversupply) and more intense competition, thus shrinking revenues.

Table 12: Generator Surplus[292] (in EUR/kW) for different plant categories (for EU28 in 2030)

Generator Surplus (EUR/kW)					
	Option 0	**Option 1(a)**	**Option 1(b)**	**Option 1(c)**	**Option 2**
	Baseline	Level playing field	Strengthening short-term markets	Demand response/ distributed resources	Fully integrated markets
Solids	394	393	146	124	108
OCGT	112	102	34	19	9
CCGT	191	178	39	29	22
Nuclear	451	490	435	418	413
Hydro	204	215	200	194	190
Solar	65	73	74	74	75
Wind onshore	117	133	137	137	137
Wind offshore	176	204	211	213	213

Source: METIS

292 Reported surplus concerns day-ahead and reserve market revenues. Some additional revenues (but minor in comparison) should be expected from the intraday and balancing markets (but were difficult to identify and report).

Similarly, the introduced measures have certain consequences on the generation production, although these tend to be relatively limited. Summarizing what has already been discussed in the dedicated assessment of each option, and presented in Table 13:

- The main impact on the electricity generation patterns appears in Option 1(a), when dispatch begins reflecting the economic merit order. Most notably, biomass generation is replaced mainly by gas and coal generation.
- Otherwise, generation patterns remain relatively stable across Options, except for some shifting of gas generation to nuclear in Option 1(b) (strengthening short-term markets). This comes as a result of the more efficient interconnection allocation and procurement of reserves, which leads to the utilisation of nuclear and lignite plants mainly for producing energy, while the more expensive gas plants are used more for reserves and balancing.
- RES E curtailment and activation of replacement reserves is steadily reduced across all options, as all measures introduce more and more flexibility to the system. In fact replacement reserves are no longer needed in Option 2.
- Procurement of Balancing Reserves also decreases substantially, from 79.6 GW in the baseline to only 29.6 GW in Option 2. The gradual drop in the required reserves is an outcome of the specific measures assumed in each case and explained in more detail in the assessment of the respective options.

Table 13: System Operation Results (for EU28+NO+CH in 2030)

	Option 0	Option 1(a)	Option 1(b)	Option 1(c)	Option 2
	Baseline	Level playing field	Strengthening short-term markets	Demand response/ distributed resources	Fully integrated markets
Net Electricity Generation (TWh)					
Total	3618	3606	3599	3588	3586
Biomass & Waste	236	78	73	72	71
Hydro[293]	632	623	618	609	607
Wind	722	726	728	729	729
Solar	303	303	303	303	303
Lignite	269	274	278	279	280
Nuclear	755	775	800	803	804
Coal	237	272	274	268	266
Gas	455	545	515	516	515
Others	10	10	10	10	10
RES Curtailment (GWh)	13.0	8.3	6.0	5.0	4.6
Balancing Procurement (GW)					
Reserve Dimensioning	79.6	65.8	42.3	42.3	29.6
of which FCR	12.4	12.4	12.4	12.4	12.4
of which aFRR	20.5	20.4	10.1	10.1	6.0
of which mFRR	46.6	33.1	19.8	19.8	11.1
Reserves via interconnections[294]	-	-	12.2	11.7	18.7
Replacement Reserves Activation[295] (GWh)	600	100	80	60	0

Source: METIS

In terms of distributional impacts across the EU regions, results are strongly related to the respective generation mix of each region, as well as to how well interconnected each region is

[293] Hydro includes pumped hydro storage whose utilisation decreases from Option 0 to Option 2.
[294] The reserves via interconnections are computed as the difference between the reserves needed to face the national risks and the procured reserves.
[295] Activated for avoidance of Loss of Load

to the others. For the regions with significant biomass generation (e.g. region 3), there are significant cost savings when moving from the baseline to Option 1(a) (level playing field). Similarly, the benefits of Option 1(b) (strengthening short-term markets) and Option 2 (fully integrated markets) are more significant for the Member States that are better interconnected (Regions 1 and 2). Option 1(c) (demand response and distributed resources) reduces costs for all regions, except for Region 5, as the competition with additional reserve resource decreases the cost for reserve procurement. Similar observations apply for the load payments and the wholesale prices. It is also worth noting how wholesale prices tend to converge as markets become more harmonised and better functioning, with the exception of Region 4 (Spain & Portugal), which has a limited interconnection to the rest of EU only via France.

Table 14: Distributional Impacts – regional perspective[296] (for EU28 in 2030)

	Option 0	Option 1(a)	Option 1(b)	Option 1(c)	Option 2
	Baseline	Level playing field	Strengthening short-term markets	Demand response/distributed resources	Fully integrated markets
Total cost – Day Ahead Market (billion EUR)					
Region 1	42.1	40.3	39.4	38.9	38.6
Region 2	6.9	5.5	4.8	4.5	4.4
Region 3	13.3	10.7	9.6	9.4	9.3
Region 4	5.5	5.3	5.0	4.9	5.0
Region 5	14.3	14.9	14.6	14.9	14.9
Total Load Payments – Day-Ahead Market (billion EUR)					
Region 1	157	161	138	131	126
Region 2	36	40	34	32	30
Region 3	26	31	30	30	30
Region 4	17	18	19	19	19
Region 5	37	37	36	36	37
Average Day-Ahead Market Price (EUR/MWh)					
Region 1	88.1	90.6	77.3	73.3	70.6
Region 2	87.6	97.2	81.6	78.0	73.6
Region 3	63.3	75.5	73.8	73.0	73.0
Region 4	49.6	53.2	55.2	54.6	55.5
Region 5	70.9	71.8	70.6	70.6	70.8

Source: METIS

[296] Regions as indicated in footnote 244.

6.2. Impact Assessment for Problem Area II (Uncertainty about future generation investments and fragmented capacity mechanisms)

6.2.1. Methodological Approach

6.2.1.1.Impacts Assessed

Similarly to Problem Area I, the assessment focused on the economic impacts of the examined options. The emphasis though is not on the operation of the power system and the integration of RES E, but on whether the market revenues can incentivize the necessary investments and – most importantly – on the relevant cost for the consumer. Inefficiencies resulting from fragmented approaches to CMs are also considered.

The impacts of the options to the environment and the society, excluding their economic aspects, are directly linked with the changes in the generation capacities of each option. Other significant, direct or indirect, impacts for the examined options were not identified.

The assessment is presented individually for each option, with qualitative analysis and references to quantitative results. The detailed modelling results for the various options, along with their interpretation, are presented in section 6.2.6.

6.2.1.2.Modelling

The modelling for this part was performed using PRIMES/OM, a specific version of the PRIMES model that can assume different types of competition in the electricity market, as well as model how CMs affect the investment decisions of the market participants. PRIMES/OM was selected over METIS for this part of the analysis, because it can model in detail the investment decisions of the market participants over an extended time-period, namely until 2050, while at the same time being able to capture the effect of different bidding behaviours from the side of the market participants (necessary to assess the impact of scarcity pricing).

In addition, PRIMES/IEM (a day-ahead and unit commitment simulator developed by NTUA) was used to assess in more detail the benefits of the energy-only market. Contrary to METIS[297], PRIMES/IEM places more emphasis on accurately simulating the market behaviour of generators by assuming specific bidding strategies followed by the market participants and departing from the usual marginal cost assumption[298]. Moreover, PRIMES/IEM was able to capture the effect of introducing locational price signals, as it

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297 Due to the differences in the two modelling approaches and underpinning assumptions of METIS and PRIMES/IEM, a direct comparison of the two sets of modelling results could be misleading.

298 The marginal cost assumption is perhaps the most usual assumption in the dispatch type of models, as it helps focus more on the effect of market design measures and departs from competition or behavioural issues. However, one cannot capture well the effect of measures like scarcity pricing under the marginal cost bidding assumptions, as the prices would fluctuate between the marginal cost of the most expensive running plant and VoLL (or price cap), which is not what is observed in practice in the market.

includes a network model. Further details on both models and the methodological approach followed can be found in Annex IV, as well as in the relevant NTUA report[299].

The above tools were complemented by a study performed using METIS, analysing the revenue related (weather-driven) risks faced by conventional generation and how these could be mitigated, while also identifying the value of co-ordinated solutions[300].

6.2.1.3.Overview of Baseline (Current Market Arrangements)

The baseline reflects the current market arrangements of Problem Area I, similar to what is described in section 6.1.1.4. In addition it is assumed that Member States put in place price caps, as well as that there may be systemic congestion in the transmission grid.

Comparing the baselines of Problem Areas I and II in modelling terms, certain differences exist in terms of figures and assumptions, mainly reflecting the differences in the respective modelling approaches[301] intended to better capture the options assessed in each Problem Area, as well as their calibration to a different version of EUCO27[302]. Under this baseline:

- Price caps apply as today[303];
- Units bid according to bidding functions by plant category[304] and not marginal costs;
- The unit commitment simulator applies a flow-based allocation of interconnections;
- Modelling includes more detailed information on generation capacities, including vintages, technology types and technical characteristics of plants;
- The day-ahead market covers only part of the load, as is the case today. A large part of the energy (especially produced by inflexible units) is nominated.
- The baseline of this Problem Area fully reflects EUCO27.

Nevertheless, both models identify similar trends concerning the operation and the revenues of the various generation types, as already presented in Problem Area I.

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299 "*Methodology and results of modelling the EU electricity market using the PRIMES/IEM and PRIMES/OM models*", NTUA (2016)

300 "*METIS Study S16*: *Weather-driven revenue uncertainty for power producers and ways to mitigate it*", Artelys (2016)

301 Further details can be found in Annex IV.

302 METIS had to be calibrated to PRIMES much earlier than PRIMES/IEM. Therefore, a preliminary version of EUCO27 was used as the basis for the calibration. The main differences of the two versions concerning the power sector can be found in Annex IV.

303 For more details please see: "*Electricity Market Functioning: Current Distortions, and How to Model Their Removal*", COWI (2016).

304 The basis is the marginal fuel cost of the plant, increased by a mark-up defined hourly as a function of scarcity, calculated for each market segment in which the respective plant category usually operates (e.g. peak, mid-merit, baseload). Further details can be found in Annex IV.

6.2.2. Impacts of Policy Option 1 (Improved energy markets - no CMs)

6.2.2.1.Economic Impacts

Option 1 assumes that Member States can no longer put in place CMs. The analysis is hence solely based on a strengthened energy-only market.

With sufficient economic certainty, investments should in principle be able to take place based on the electricity price signal alone, provided that the price signal is not significantly distorted. Further, the electricity price, and its behaviour, should stimulate not only investment in sufficient capacity when needed (be it production or demand), but also in the right type of capacity. A steady electricity price, one that does not vary significant on an hour-to-hour basis, should steer investment to the types of capacity that can operate steadily at lowest production cost. A rapidly fluctuating electricity price should steer investment to capacity that can ramp-up and ramp-down very quickly and can take advantage of high prices at short notice and avoid operation when prices are too low. The shift to variable generation will increasingly require fast-ramping and highly flexible generation and cause the market exit of less flexible types of generation capacity. Investment uncertainty and varying prices are not a unique feature to the electricity industry[305].

In this way, the effect of variable renewables, insofar as their deployment will increase the variability of the electricity price, should stimulate investment in the flexible capacity needed to keep the system in balance at all times. Ensuring that prices can reflect market fundamentals is key to this and removing as many potential distortions on electricity prices is critical to enabling it to play this function.

Indeed, the analysis performed with PRIMES/OM supports the arguments above, showing that an energy-only market can in general deliver cost-efficiently the necessary investments in thermal capacity (especially flexible one). The enhanced market design will also improve the viability of RES E investments, but electricity market revenues alone might not prove sufficient in attracting investments in RES E in a timely manner and at the required scale to meet EU's 2030 targets. (See in this regard also the box on RES E investments in Section 6.2.6.3).

Moreover, PRIMES/IEM results show that undistorted, energy-only markets can significantly decrease load payments by around EUR 50 billion[306] in 2030. The largest part of these savings is attributable to the improvements in the short-term markets and the participation of demand response in the market, representing EUR 20 billion and EUR 26 billion savings respectively in 2030. The implementation of measures introducing a level playing for all

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[305] See in this respect e.g. the report by Frontier Economic on *"Scenarios for the Dutch electricity supply system"*, p. 134. https://www.rijksoverheid.nl/documenten/rapporten/2016/01/18/frontier-economics-2015-scenarios-for-the-dutch-electricity-supply-system

[306] The benefits become almost double compared to Option 1(c) as assessed with METIS, due to the additional distortions included in the baseline and measures to address them, on top of the expected differences due to the different modelling approach. The two figures give a satisfactory range on the possible benefits for Europe from an improved energy only market design.

technologies and removing price caps brings EUR 5 billion savings in 2030 and at the same significant more cost-efficiency to the system, as explained in Section 6.1.2.1.

As resources are better utilised across the borders compared to the baseline, and demand can better participate in markets, undistorted energy-only markets are able to improve the overall cost-efficiency of the power sector significantly. Equally, it can ensure resource adequacy (See in the regard also Section 6.2.6.3).

It thus follows that by improving the energy markets, the need of government intervention to support investments in electricity resources is reduced

6.2.2.2.Who would be affected and how

As this option encompasses to the largest extent the options discussed under Problem Area 1, the assessment made there as to who would be affected and how applies here as well.

With regard to more variable pricing, they will benefit owners of flexible resources, such as flexible **generation capacity, storage and demand response**, and incentivise them to come to or stay in the market. In this end, they will provide the motor for more innovative services and assets to be deployed.

End consumers will be affected insofar as changes to the wholesale price are passed on to them in their retail price. However, more variable prices will not necessarily be felt by end-consumers as they can be hedged (particularly households) against this volatility in their retail contracts or through wholesale market arrangements. In fact, more variable pricing will incentivise the development of more sophisticated energy wholesale market products allowing price and volume risks to be hedged more effectively. **Power exchanges** would be impacted by removal of price caps as they will be required to introduce changes to systems and practices.

Minimising investments and dispatch distortions due to transmission tariff structures would mostly affect **generators**. Positive impacts on their revenues would be expected due to lower connection charges or tarrifs.

TSOs will be affected by improvements in locational price signals as it would likely mean that they hold and operate networks over more than one price zone. To a lesser extent this applies to **power exchanges** as these are often already operating in different price zones today.

Spending of the congestion income to increase cross-border capacity may have impact on **end consumers**, where the congestion income is used for the reduction of tariffs. But this should be outweighed by the positive effect of more cross-border capacity being available, and the benefit this has on competition and energy prices.

6.2.2.3.Administrative impact on businesses and public authorities

As this option encompasses to the largest extent the options discussed under Problem Area I, the assessment made there as regards administrative impacts made there also applies here[307].

Overall, the administrative impact on **businesses and public authorities** should be limited as, even if the measures associated with Option 1 (in addition to those assessed under Problem Area I) require changes, they are not fundamentally different from the tasks performed already under the baseline scenario.

More variable pricing will incite the development of more sophisticated energy wholesale market products allowing price and volume risks to be hedged more effectively. This should help reduce lower overall risks to **businesses**.

6.2.3. Impacts of Policy Option 2 (Improved energy markets – CMs only when needed, based on a common EU-wide adequacy assessment)

6.2.3.1.Economic Impacts

This option builds on a strengthened energy market (Option 1). Indeed, as developed in Section 2.2.1, undistorted energy price signals are fundamental irrespective of whether generators are solely relying on energy market income or also receive capacity payments. Therefore, the measures aimed at removing distortions from energy-only markets are 'no-regrets' and assumed as being integral parts of Options 2 and 3.

In addition, the option assumes the presence of CMs but only in those Member States for which a resource adequacy assessment performed at European level has demonstrated a resource adequacy problem. As no restrictions are placed on these CMs, it is assumed they foresee implicit cross-border participation (i.e. only taking into account imports and exports in the dimensioning of the CM, without any remuneration of foreign capacity).

In order to highlight the importance of considering the regional aspects in a generation adequacy assessment, Artelys performed an independent study[308] assessing the capacity savings that can be obtained from a European approach in capacity dimensioning for resource adequacy in comparison to a resource adequacy assessment conducted at Member State level.

The mode used jointly optimises peak capacities given security of supply criteria[309] for two reference cases – without cooperation (capacities are optimised for each country individually, as if countries could not benefit from the capacities of their neighbours) vs. with cooperation (capacities are optimised jointly for all countries, taking into account interconnection

[307] For the impact of the additional measures (removing price caps, introduction of locational price signals, etc.), a detailed analysis is also presented in Annexes 4.1 to 4.4.

[308] *"METIS Study S16: Weather-driven revenue uncertainty for power producers and ways to mitigate it"*, Artelys (2016). The results of this study are spelled-out in more detail in Annex 2.2.

[309] A value of 15k€/MWh for loss of load is used and system adequacy is assessed on 50 years of hourly weather data. For more details on the characteristics of capacity dimensioning, see Annex 2.2.

capacities (i.e. NTCs). The difference in installed capacity between the two cases reveals the savings could be made from cooperation in investments.

Results show that almost 80 GW of capacity savings across the EU can be achieved with cooperation in investments. This represents a gain of EUR 4.8 billion per year of investments[310] when comparing the two extremes. A reason for these savings is that Member States have different needs in terms of capacity with peak demands that are not necessarily simultaneous. Therefore, they can benefit from cooperation in the production dispatch and in investments. It should be noted that this figure does not assess at which stage Member States are currently (i.e. whether some Member States already benefit from the capacities of their neighbours), as the benefits have already been reaped by some. It should also be noted that this figure does not include savings on production dispatch, which could lead to much higher monetary benefits.

PRIMES/OM was used to assess the impact of introducing CMs on a certain number of countries, with the CMs foreseeing implicit cross-border participation. The runs assumed that four countries were justified based on a EU-wide adequacy assessment, to have a CM: UK, Italy, Ireland and France. This assumption was based on a selection of countries from the Sector Inquiry on Capacity Mechanisms (as the model always ensures that the expected security of supply levels are always met).

The analysis shows that the introduction of CMs lowers wholesale prices, but to a limited degree, primarily in the MS introducing CMs, but also to all EU countries due to the assumed well-functioning markets. On the other hand this does not translate to reduced Load Payments for the consumers on a EU level, as the CM related costs slightly exceed the reductions in the cost of the wholesale energy market in 2030. This difference though becomes quite significant in the longer term, making Option 1 cheaper than Option 2 by an average of EUR 4 billion/annum when comparing over the period 2021-2050. Interestingly enough, the consumers of the Member States introducing CMs face a EUR 7 billion increase in costs in 2030, while the cost for all other EU Member States drop by a similar amount.

6.2.3.2. Who would be affected and how

EU-wide resource adequacy assessments would benefit **consumers** through maintaining high standards of security of supply while lowering costs through reduced risk of over procurement of local assets as foreign contribution to national demand and demand side flexibility would be sufficiently taken into account.

ENTSO-E would be required to carry out an EU-wide resource adequacy assessment based on national raw data provided by TSOs (as opposed to a compilation of national assessments). **ENTSO-E** would also have to provide an updated methodology with probabilistic calculations, appropriate coverage of interdependencies, availability of RES E and demand side flexibility and availability of cross-border infrastructure. **NRAs**/ **ACER** would be

[310] The 80 GW of capacity savings are a result of optimal investment decisions on EU level, based on an EU approach vs a national approach. Efficient market functioning can also provide efficient investment signals leading to more efficient investments. See section 6.2.6.3.

required to approve the methodology used by ENTSO-E for the resource adequacy methodology and potentially endorse the assessment. **TSOs** would be obliged to provide national raw data to ENTSO-E which will be used in the EU-wide resource adequacy assessment.

Member States would be better informed about the likely development of security of supply and would have to exclusively rely on the EU-wide resource adequacy assessment carried out by ENTSO-E when arguing for CMs.

With the updated methodology provided by ENTSO-E, intermittent **RES generators/ demand-side flexibility** would be less likely to be excluded from contributing to resource adequacy.

6.2.3.3.Impact on businesses and public authorities

The main burden would be for ENTSO-E having to provide for a single 'upgraded' methodology and to carry out the assessment for all EU countries. Important to note is that ENTSO-E has already been carrying out an EU-level resource adequacy assessment based on Union legislation. However, the methodology used has to be upgraded which would require increased manpower. Nonetheless, the **administrative costs** of this 'updated' assessment are expected to be marginal compared to the economic benefits that would be reaped. It is estimated that these these costs[311] would range from EUR 4-6 million per year (representing mainly personnel and IT costs).

6.2.4. Impacts of Policy Option 3 (Improved energy market – CMs only when needed, plus cross-border participation)

6.2.4.1.Economic Impacts

This option builds on Option 2, i.e. a strengthened energy market and CMs only in Member States where justified by a European adequacy assessment. In addition, this option provides an EU framework for explicit cross-border participation in CMs.

Explicit cross-border participation lowers overall system costs compared to implicit participation, as it corrects investment signals and enables a choice between local generation and alternatives. As more capacity will be participating in the CM, than in the implicit participation case, competition will be more intense and thus CM payments lower. In addition, the enhanced competition will extend also to the wholesale market, thus leading to lower market clearing prices.

Based on the same setup as in Option 2 (Improved energy market – CMs only when needed, based on EU resource adequacy assessment) only now with explicit cross-border participation (i.e. remunerating foreign resources for their services) instead of only implicit (i.e. only taking into account imports and exports in the dimensioning of the CM, without any remuneration of

[311] The economic costs linked to resource adequacy assessments are based on own estimations, resulting from discussions with stakeholders and experts. For more details, see Annex 5.1.

foreign capacity), PRIMES/OM estimates that explicit cross-border participation would result in significant savings. Results show that explicit participation brings savings of EUR **2 billion** (in 2030) compared to implicit participation, with savings significantly increasing in the long run to more than EUR 100 billion over the whole projectin period of 2021-2050 (i.e. about EUR 3.5 billion per annum). The main reason is enhancement of competition in the CM auction and the resulting lower auction prices.

By remunerating foreign resources for their services, this option is likely to better ensure that the investment distortions of uncoordinated national mechanisms present in Option 2 are corrected and that the internal market able to deliver the benefits to consumers.

6.2.4.2.Who would be affected and how

A positive impact of cross-border capacity mechanism would be expected on the foreign capacity providers, **generators, interconnectors and aggregators**. They would receive the possibility to participate directly in a national capacity auction, with availability obligations imposed on the foreign capacity providers and the interconnecting cross-border infrastructure. Foreign capacity providers/ interconnectors would be remunerated for the security of supply benefits that they deliver to the CM zone and but would also receive penalties in case of non-availability.

NRAs/ACER would be required to set the obligations and penalties for non-availability for both participating generation/demand resources and cross-border transmission infrastructure. **ENTSO-E** would be required to establish an appropriate methodology for calculating suitable capacity values up to which cross-border participation would be possible. Based on the ENTSO-E methodology**, TSOs** would be required to calculate the capacity values for each of their borders. They might potentially be penalized for non-availability of transmission infrastructure. **TSOs** would also be required to check effective availability of participating resources.

6.2.4.3.Impact on businesses and public authorities

Providing an EU framework with roles and responsibilities of the involved parties would enable explicit cross-border participation (as already required by the EEAG). Although the cost of designing cross-border participation in CM depends to some extent on the design of the CMs, an expert study[312] estimated that such cost corresponds roughly to 10% of the overall cost of the design of a CM[313]. In addition, they estimate costs associated with the operation of a cross-border scheme i.e. additional costs if cross-border participation is facilitated to amount to 6-30 FTEs[314] for TSOs and regulators combined. Providing for an EU framework would remove the need for each **Member State** to design a separate solution and potentially reduce the need for bilateral negotiations between **TSO**s **and NRAs**, reducing the overall impact on these authorities. According to the same study, TSOs and NRAs bear the

[312] Thema (2016), *Framework for cross-border participation in capacity mechanisms* (First interim report)

[313] The same expert study also found that the overall cost of of the design are fairly small compared to the overall cost of the CM (remuneration of the participation ressources).

[314] FTEs in other phases refer to (annually) recurring costs.

main costs related to cross-border participation as they have to check eligibility and ensure compliance. The study estimates cost savings of 30% on these eligibility and compliance costs compared to the baseline. It would also reduce complexity and the administrative impact for **businesses** operating in more than one zone.

6.2.5. Environmental impacts of options related to Problem Area II

The impacts of these measures to the environment are very limited, as they mainly influence the generating capacity but not so much the operation of the units, which is the source of emissions. The actual emissions depend on the merit order and the relation of the marginal cost of coal in comparison to the marginal cost of gas. This in turn depends on the CO_2 price and the relation of coal versus gas price, and not on whether there is a CM in place or not.

6.2.6. Overview of modelling results for Problem Area II

6.2.6.1.Improved Energy Market as a no-regret option

Several facts speak in favour of market design which relies on an improved energy market as the driver for investment and operation. As already described in the assessment of Problem Area I, the improvements in the wholesale market described under Option 1 of Problem Area I (level playing field, strengthening short-term markets, pulling demand response and distributed resources into the market) are expected to bring significant benefits and reduce the need to correct market failures with capacity markets. These benefits are further enhanced when considering the additional measures considered in this Option (e.g. removal of price caps, a process which leads to the introduction of locational price signals reflecting systematic congestion, limiting curtailments of interconnector capacity).

The benefits of further improving the market in this way, assessed this time using the PRIMES/IEM model, are presented in Table 15 below. The level of the reported figures in Table 15 are higher compared to Table 10 due to the inclusion of more distortions in the baseline of PRIMES/IEM, as well as the use of scarcity bidding, instead of marginal cost bidding in METIS[315].

Table 15: Cost of supply in the wholesale market in the year 2030[316]

Load Payments (billion EUR)				
	Day-ahead Market	**Intra Day Market**	**Reserves and balancing**	**Total**
Current Market Arrangements (in context of low price caps, systematic congestion)	326.2	22.1	7.7	356.0
Level playing field + removal of low price caps	327.5	17.1	6.8	351.4
Strengthening short-term markets + removal of low price caps, locational price signals	317.6	11.6	1.9	331.2
Demand response / distributed resources into the market + removal of low price caps, locational price signals, demand response in day-ahead	300.4	4.0	1.0	305.4

Source: NTUA modelling (PRIMES/IEM)

Overall, despite differences in the modelling approaches, results of PRIMES/IEM are fairly consistent with METIS results used to access the options from Problem Area I, especially concerning the ranking of the respective options. The results indicate that the "improved energy market" Option could significantly decrease wholesale supply costs by around EUR 50 billion in the year 2030. As a consequence, the unit cost of generation paid by the consumers would drop from 102.9 EUR/MWh to 94.7 EUR/MWh, the largest part of which is attributable to the participation of demand response in the market[317].

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315 At the same time the assumption that CHP, small scale RES E and biomass retain (implicitly in some cases) priority dispatch in PRIMES/IEM in the first three examined cases – but not for small scale RES in the last one -, implies lower percentage changes when moving between the first three options, due to the smaller generation affected by the measures, but at the same time a more significant one for the last option. More details on the exact assumptions can be found in Annex IV.

316 The rows correspond to the respective options of problem area I (except Option 2). In addition though Option 1(a) (level playing field) is complemented by the removal of price caps; Option 1(b) (strengthening short-term markets) is complemented by the introduction of locational price signals; and Option 1(c) with demand response participating also in the day-ahead market (which could not be captured by METIS, as it captured demand response in the intraday and balancing markets only). The last row reports the aggregate costs of Option 1 of Problem Area II.

317 Contrary to METIS, in PRIMES/IEM demand response resources participate also in the day-ahead market, thus bringing additional savings for the relevant Option. The impact is much more significant in this case because the day-ahead market covers the vast majority of transactions.

The above analysis highlights the importance of an improved market design, with all the measures described under Option 1(c) of Problem Area I, together with scarcity pricing and the proper locational signals (as added under Option 1 of Problem Area II), irrespective of whether generators are solely relying on energy market income or also receive capacity payments. Therefore the measures aimed at removing distortions from energy markets are considered as 'no-regrets'.

6.2.6.2.Comparison of Options 1 to 3

In order to better assess the dynamic behaviour of markets and how markets can also provide investment signals, modelling analysis was performed using PRIMES/OM[318, 319]. Option 1 assumes an improved energy-only market for all Member States. Options 2 and 3 assume that the improved energy-only market is complemented in certain cases by a national CM[320,321] as a means for the Member States to address possible forecasted resource adequacy problems in their markets, on the basis of a resource adequacy assessment performed at the European level. The difference between the two options is that Option 3 assumes that the CM foresees rules for effective, explicit cross-border participation, while Option 2 does not.

For the scope of this assessment, four countries were assumed to be in need of a CM: France, Ireland, Italy and UK. This hypothesis was not based on a resource adequacy analysis, but on the CMs examined under DG COMP's Sector Inquiry, focusing specifically on countries with market-wide CMs. (Results could differ if different countries were selected, which is why a sensitivity, presented below, was performed).

The main conclusions when comparing Options 1-3 are presented in Table 16 and can be summarized in the following:

318 PRIMES/OM delivers results complementary to the ones of market simulation models, like METIS and PRIMES/IEM, as its focus is on investments. The main difference of PRIMES/OM with other energy system investment models, like PRIMES, is that while PRIMES model analyses revenues/costs at the level of the generation portfolio, the PRIMES/OM evaluates the probability of plant survival depending on the economic performance calculated individually for each plant. A detailed description of PRIMES/OM can be found in Annex IV.

319 The results will not be compared directly to the baseline as it was not technically possible to produce robustly this scenario using PRIMES/OM. Nevertheless this does not affect the assessment, as all options build upon the preferred option of Problem Area I.

320 The simulation of the CM auction by country, which is based on an estimation of a demand curve for capacity procurement, takes into account imports and exports in the context of market integration using power flow allocation of interconnection capacities. Therefore, the capacity procurement is configured so as to avoid demanding for unnecessary capacities, as imports are considered to contribute to resource adequacy. Similarly, exporting countries configure demand for capacity procurement taking into account capacity needed to support exports.

321 When a country is assumed to have a CM in place, it is assumed that generators no longer follow scarcity pricing bidding behaviour, but shift to marginal cost bidding. This is partly a result of competition, as more generation remains in the market, as well as the expectation that when a plant gets a CM remuneration as a result of an auction it foregoes revenues that would otherwise be needed to be covered from the day-ahead market (e.g. because it signs a reliability option contract or a contract for differences with a strike price effectively acting as a price cap to the generator's revenues from the energy market).

- The load payments for the three Options are very comparable when assessed at the EU28 level. For the year 2030, Option 3 (Improved energy market – CMs only when needed, plus cross-border participation) is slightly cheaper by EUR 1 billion compared to Option 1 (Improved energy markets - no CMs) and by EUR 2 billion compared to Option 2 (Improved energy markets – CMs only when needed, based on a common EU-wide adequacy assessment);
- Results actually show that Option 3 is consistently cheaper than Option 2 throughout the projection horizon until 2050 and on a EU28 level. This is mainly due to the lower cost of the CMs, as through the cross-border participation more resources can compete for the relevant payments;
- As a result of the above, the average annual cost of total demand is very close for Option 1 and Option 3, with the lowest cost option alternating along the years. Option 3 is always less costly for the consumer than Option 2 though.
- When comparing the Options for the whole projection period, i.e. 2021-2050, Option 1 is found to be EUR 17 billion cheaper than Option 3 (on average about EUR 0.5 billion/annum) and EUR 120 billion cheaper than Option 2 (on average EUR 4 billion/annum). The main reason for this difference is that CMs provide incentives to retain capacity on the system that otherwise would have exited the market. This cost is somewhat balanced by the slightly lower energy prices observed in the market, although the final cost to the consumer comprises of both the energy and the CM cost.

Table 16: Main Impacts over the projection period 2020-2050 on EU28 level

	2020	2025	2030	2035	2040	2045	2050
Load Payments (billion EUR)							
Option 1	241	316	351	419	447	557	516
Option 2	241	312	352	428	454	560	530
Option 3	241	306	350	426	452	553	526
Load Payments for energy and reserves (billion EUR)							
Option 1	241	316	351	419	447	557	516
Option 2	241	302	340	417	443	548	518
Option 3	241	297	340	417	443	543	516
Load Payments to capacity mechanisms (billion EUR)							
Option 1	-	-	-	-	-	-	-
Option 2	-	11	11	11	11	11	12
Option 3	-	9	10	9	10	10	10
Average SMP (billion EUR)							
Option 1	74	95	103	118	115	135	122
Option 2	74	91	100	117	114	133	123
Option 3	74	89	100	117	114	132	122
Average cost of total net demand (EUR/MWh)							
Option 1	80	102	111	127	125	146	132
Option 2	80	101	111	129	127	147	135
Option 3	80	99	110	129	126	145	134

Source: NTUA Modelling (PRIMES/OM)
Note:Option 1: Improved energy markets - no CMs
Option 2: Improved energy markets – CMs only when needed, based on a common EU-wide adequacy assessment
Option 3: Improved energy market – CMs only when needed, plus cross-border participation

In order to better understand the impacts[322] of the CMs and the effect of cross-border participation, Table 17 presents the impacts in 2030 for the three following groups of countries: (a) the countries implementing a CM, (b) their direct neighbours and (c) the rest of the EU countries.

Results for Option 2 shows that by introducing a CM in the assumed four countries, the actual distribution of cost varies among the different groups of countries. Countries implementing a CM are significantly burdened, mainly due to the cost of the CM, while their neighbours benefit from it.

[322] The impacts of CMs on the energy mix were very limited, inducing only some limited switching in electricity generation from coal to gas plants.

In particular countries implementing the CM are burdended with an additional EUR 6.8 billion of costs, while the cost of their neighbours drops by EUR 3.6 billion. Even the cost of the rest of the EU countries drops by EUR 2.9 billion. The cost of energy and reserves is reduced for all countries[323]. In the countries implementing a CM the cost is reduced about two times more than in the rest coutries, thus leading to lower payments for energy and reserves. However, these reductions are outbalanced by the CM costs, borne solely by the countries introducing CMs. The CMs induce an additional EUR 11 billion of payments, part of which are attributed to the 5 GW of capacity which would otherwise have retired early in the absence of CMs.

Moving to Option 3, i.e. assuming explicit cross-border participation in the CMs, the results compared to Option 2 improve in terms of cost-efficiency, not only for the whole EU as presented above, but also for the countries implementing CMs. On the other hand the benefits for the countries without a CM are slightly reduced.

In particular, the analysis for the year 2030 shows that explicit cross-border participation is still worse-off for the countries with a CM compared to the energy-only market, costing EUR 3.6 billion more then the energy-only market, but better than implicit cross-border participation, which costs an additional EUR 3.2 billion to the countries with CM.

In general, modelling results indicate that a CM, compared to an energy-only market, is likelier to keep more capacity in the system, part of which would have otherwise exited due to making losses in the energy market. As more capacity is kept in the Member States with a CM, less capacity is needed in the other Member States, especially the neighbouring ones, which then rely more on imports.

As it was discussed above, these results are influenced by the specific choice of countries assumed to have a CM. To address this issue, an additional sensitivity was performed, comparing the cases of all Member States introducing a CM, either with implicit or explicit cross-border participation (same applying for all). Results show that the case of CMs with explicit cross-border participation is less costly, with load payments being EUR 7 billion less (about 2%) in the year 2030. Half of this benefit is coming from the reduced CM payments and half from the reduced energy and reserve payments.

[323] This result is related to some specific characteristics of these countries. France is heavily exporting electricity based on nuclear and this is not affected by the establishment of a CM in France. This is also the reason why energy costs drop across Europe. The UK and Italy heavily depend on CCGT plants in the context of the scenario examined and, in addition, have limited free space in interconnections, because they are saturated by import flows of nuclear energy coming from France.

Table 17: Distributional Impacts of Options for Member States in 2030[324]

	Option 1	Option 2	Option 3
	Improved energy markets - no CMs	Improved energy markets – CMs only when needed, based on a common EU-wide adequacy assessment	Improved energy market – CMs only when needed, plus cross-border participation
Load Payments in 2030 (billion EUR)			
MS with CMs	133	140	137
MS directly neighbouring MS with CM	135	131	132
Rest of the MS	82	79	80
Load Payments for energy and reserves (billion EUR)			
MS with CMs	133	129	127
MS directly neighbouring MS with CM	135	132	132
Rest of the MS	82	80	80
Load Payments to capacity mechanisms (billion EUR)			
MS with CMs	0	11	10
MS directly neighbouring MS with CM	0	0	0
Rest of the MS	0	0	0
Average SMP (EUR/MWh)			
MS with CMs	104	100	98
MS directly neighbouring MS with CM	102	100	100
Rest of the MS	103	101	101
Cancelling of Investments or Early Retirements of Capacity in 2021-2030 (GW)[325]			
MS with CMs	18	9	9
MS directly neighbouring MS with CM	35	41	42
Rest of the MS	10	10	11

Source: NTUA modelling (PRIMES/OM)

The main reason for the overall improved performance and reduced costs of Option 3 compared to Option 2 is the enhancement of competition in the CM auction and the resulting lower auction prices when allowing for explicit cross-border participation. This reduction

[324] Impacts comparing the effects to countries assumed to have CMs and countries without. The 4 countries assumed to have CMs in 2030 (France, Italy, UK, Ireland) were chosen based on the finding of DG COMP Sector Inquiry. No specific assumption was made for the design of the relevant CMs. Differences are due to the peculiarities of each national energy system, mainly related to its power mix and its level of interconnections. Results could be different if other MS had been chosen.

[325] The values under "cancelling of investments or early retirements of capacity" represent excess capacity which becomes redundant due to the improved market functioning. Early retirement in the model is market-based, coming as a result of anticipating a negative present value of earnings above operation costs in the future, in comparison to the remaining value of the plant.

lowers the revenues of generators from a CM, but the probability of capacity reduction does not significantly increase, compared to the case with implicit cross-border participation. Explicit cross-border participation in the CM auctions implies that competition is stengthened not only in the CM, but also in the electricity wholesale market.

6.2.6.3.Delivering the necessary investments

Despite the different modelling approaches followed, the analysis with both METIS and PRIMES/IEM reach a similar conclusion: improving the electricity market design is a no regret option for the society as a whole. It is expected to reduce both the cost of operating the power system, as well as the final cost for the consumers.

At the same time though the two models showed that these savings come to the detriment of the thermal generator revenues, which are expected to be reduced compared to the baseline. This modelling conclusion is a consequence mainly of the following two reasons:

- on one hand, the improved market design increases competition in the market, by bringing more resources into the market and better utilisation of interconnections;
- on the other hand, capacities are assumed to be constant due to the nature of the modelling (static, focusing on 2030 based on the same capacities across all options).

The combination of the two points above leads to a market with overcapacity[326] and thus low prices, since there is no scarcity and there is sufficient capacity of flexible resources. In reality though, the low prices in a well-functioning market would serve as a signal for lower investments and exit of loss-making generators. Therefore this overcapacity should either never appear or only be temporary.

The above dynamic interactions were better captured with PRIMES/OM, which simulated investment behaviour till 2050[327]. In an energy-only market context, PRIMES/OM projected that 63 GW of capacity would either be retired early or the relevant investments would be cancelled in the period 2021-2030. About half of it would come from (mainly old) coal plants and another half from peaking units or steam turbines fuelled by oil and gas.

The reason for retiring capacity and cancelling investments is the unprofitable operation of the units. From the results it is indicated that the market can be successful in maintaining CCGT in operation and, partly, peak devices. On the other hand it does not provide sufficient incentives to retain old coal and old oil/gas steam turbine power plants, which are loss-making.

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326 Moreover the capacity mix is not optimal any more.

327 All modelling runs assume certain reliability standards are met (i.e. security of supply concerns are always met)

Table 18: Power generation[328] capacity in EU28

	Power Generation Capacity (GW)			Cancelling of Investments or Early Retirements of Capacity (GW)		
	2030	**2040**	**2050**	**2021-2030**	**2031-2040**	**2041-2050**
Total	1,094	1,271	1,504	63	68	48
Coal & Lignite	77	45	14	32	45	33
Peakers & Steam turbines (oil/gas)	12	6	6	28	16	8
CCGT	158	165	175	0.3	7	4
Nuclear	110	124	122	2	0	2

Source: NTUA Modelling (PRIMES/OM)

In this context of adjusting capacities, the profitability[329] of thermal generation changes significantly for the better. Scarcity pricing and the reduction of overcapacity are the main drivers for this. Table 19 below shows how the adjustment of capacities, together with scarcity pricing, would affect wholesale prices and allow thermal plants to at least recover their total costs from the market.

Table 19: Effect of adjusting capacities to wholesale market prices in 2030

	Day-Ahead Market Price Before Adjusting Capacities	Day-Ahead Market Price After Adjusting Capacities
Average Price (EUR/MWh)	89	103
Baseload	80	93
Mid-merit	90	103
Peak load	94	137
Spread (EUR/MWh)	14	44

Source: NTUA Modelling (PRIMES/IEM, PRIMES/OM)[330]

In this context, the market seems able to deliver to a large extent the necessary investments for all competitive technologies in the long term. A new CCGT plant, which is the marginal technology, constructed post-2025 (when overcapacity is gradually resolving) will likely remain profitable over the following 20 years of its operation. If this plant is part of a larger

[328] Reported generation capacities do not include capacities of CHP plants. Reported figures on cancelled investments do not include 2 GW of cancelled nuclear investments in 2021-2030 and another 2 GW in 2041-2050.

[329] Profits are highly dependent on the assumed fuel costs, technology costs and CO_2 price. Therefore the discussion in this Section should be read in a probabilistic context, i.e. the "likelihood" of the investments being profitable, similar to how the modelling of investment decisions was performed. Concerning the specific assumptions used, PRIMES/OM was based on the relevant PRIMES EUCO27 projections, reported in Annex IV.

[330] PRIMES/IEM results are before capacity adjustment, PRIMES/OM after adjustment. Similar assumptions and the same bidding strategies were used in both models, thus results are comparable, within the limitations of each modelling approach.

portfolio, especially if it includes competitive RES E technologies, then it will be able to better hedge its risks and further increase the likelihood that the whole portfolio will be profitable.

More specifically per technology:

CCGT	Scarcity bidding succeeds in maintaining the vast majority of CCGT capacity, a large part of it being new investments in the period 2021-2030. These plants have a variety of revenue sources (day-ahead, intraday, balancing, reserves) and the projected increase in ETS prices makes them economically more attractive to operate. As a result CCGT plants are dispatched more often at full capacity.
Nuclear	Nuclear plants do not have any revenue issues, due to their low marginal cost. Note that new investments in nuclear appear only in the long-term.
Coal / Lignite	These plants have the biggest revenue problems, as market revenues prove insufficient even to cover their fuel and variable (non-fuel) costs. There was very limited new investment in the projections even in the baseline, so this issue mainly concerns decisions for the refurbishment of coal plants.
Peak devices	Peak units and steam turbines (many of them old) do not produce comfortable revenues until 2035[331]. Around that period though and due to the strong investments in variable RES E and the increasing needs for flexible capacity, the situation turns around, rendering these units very profitable.
RES E (excl. biomass)	The situation for RES E is contrasted, depending on the level of maturity of RES E technologies. Even if some less advanced RES E technologies would need support to emerge as part of the power generation mix towards 2030, this is not the case for many competitive RES E technologies, such as hydro, onshore wind and solar PV (at least in some parts of Europe)[332]. For a more elaborate discussion on this point see the text box below on RES E investments and market design.

331 "*METIS Study S16"* shows that peakers' revenues highly depend on the occurrence of scarcity hours that happen mainly during very cold years, which constitutes an additional risk for peakers who rely on scarcity prices to generate revenues. On the contrary, base-load producers have more stable revenues from one year to the other.

332 A more detailed analysis can be found in the RED II impact assessment, specifically in Annex 5, where a detailed analysis on the viability of RES E projects is presented for the period post-2020.

CHP (incl. biomass)	CHP[333] remains unprofitable over the whole projection period when considering only their electricity market related revenue streams. It should be considered though that the main use of these plants is assumed to be the production of industrial steam/heat, with electricity being a side-product. Therefore, no conclusion should be made based on these partial results. Similar for biomass (outside industrial CHP), additional revenues are assumed to come from support schemes and the value of heat when producing heat for district heating.

The following table summarizes the projected profitability for all generation technologies over the period 2020-2050:

Table 20: Average profits or losses[334] for different plant categories in the case of an energy only market over the projected horizon 2020 – 2050 in EUR/kW for EU28

	2020	2025	2030	2035	2040	2045	2050
Total	-46.9	9.1	35.7	78.4	68.8	129.2	80.5
Solids	69.9	94.8	1.6	-111.5	-80.9	-89.7	-207.7
Steam turbines oil/gas	-66.2	-116.7	-117.3	-93.8	-90.7	-68.5	-120.9
CCGT	-75.1	-55.6	-23.2	27.6	-23.5	21.1	-59.6
Peak	-53.7	-50.1	-51.9	-11.8	224.2	344.1	36.8
Nuclear	-47.5	102.8	141.0	249.4	233.8	374.5	259.4
Lakes	144.0	162.3	185.6	205.9	211.9	270.5	263.4
Run of River	268.4	309.3	335.4	355.3	304.9	345.3	209.0
Geothermal	153.3	235.4	313.8	438.3	477.1	443.4	356.1
Wind onshore	1.9	30.7	82.2	117.2	118.5	173.1	142.1
Solar PV (large)	-63.0	-1.2	25.6	58.6	49.0	86.1	62.5
RES (small)	-115.0	-101.4	-48.5	34.7	19.1	24.9	5.0
Wind offshore	-6.2	-83.8	-85.9	-18.2	2.6	127.7	55.9
Biomass	-137.9	-171.2	-141.3	-59.0	-74.1	20.5	13.2
Solar thermal	-678.7	-666.4	-466.2	-422.0	-385.3	-265.1	-415.0
Tidal	-5,569.9	-4,105.4	-308.5	-252.8	-175.7	-116.0	-130.0
CHP solids	-136.9	-203.5	-208.5	-227.6	-315.5	-364.8	-434.8
CHP gas	-163.8	-185.8	-169.3	-128.4	-207.7	-235.5	-328.0
CHP biomass	-338.5	-336.1	-324.0	-289.9	-292.3	-128.3	-90.1
CHP oil	-333.2	-459.2	-487.9	-372.3	-367.8	-629.5	-413.8

Source: NTUA modelling (PRIMES/OM)

It is important to highlight that the above analysis has been performed per individual plant basis. Although this reflects project finance type of decisions, it does not reflect portfolio-based decisions, which are closer to the usual power sector business model for utilities, due to economies of scale. The portfolio approach (e.g. investing in both wind and peak generators)

333 The category of CHP plants includes only those which serve industrial steam and district heating as their main function. Other CHP plants have been appropriately distributed within the capacities of the respective technologies.

334 The reported results concern financial evaluation at individual plant level. In the context of PRIMES/OM, profits or losses are defined as follows: revenues from day-ahead market, revenues from reserve market, revenues from CM (if applicable) minus sum of fuel costs, variable non-fuel costs, O&M fixed costs and capital costs. For capital costs the model estimates the not-yet amortized value of initial investment expenditure for old plants (including cost of refurbishment if applicable) and the investment expenditures for new investments. As these are aggregate numbers, they approximate but are not equal to the missing money (as when calculating aggregate profits, one unit's losses may cancel out with another unit's profits, while when calculating missing money you only add the losses).

allows the sharing of risks between different technologies, directly improving the performance of the investments.

Similarly the above analysis does not consider the existence of any type of contracts between supply and demand, be it long-term contracts, futures (e.g. EEX hedging products) or even typical contracts between utilities and residential/commercial consumers. Such contracts, concluded on a purely voluntary market basis, would again transfer part of the risk of the generators to consumers, in exchange of higher security of supply, protection against price spikes and more stable payments, allowing both sides to better manage their risks. This would in turn increase the likelihood of the investments turning out to be profitable.

The above analyses also highlights that the market, of improved along the lines with the measures assessed in the present impact assessment, can deliver to a large extent the necessary investments for a wide range of technologies in the long term, thereby reducing the need for government intervention to support investment in electricity resources.

Box 7: RES E investments and market design

Amongst all sectors that make up our energy system, electricity is the most cost-effective to decarbonize. Currently about one fourth of Europe's electricity is produced from renewable energy sources. Modelling indicates that the share of RES E in electricity generation needs to almost double by 2030 in order for the EU to meet its 2030 energy and climate targets.

A functioning market is the most efficient tool to implement the decarbonisation agenda at least costs while securing electricity supplies at all times.

The Commission's ambition for the post-2020 context is that renewable electricity generators can earn an increasingly larger fraction of their revenues from the energy markets.

This ambition requires adapting the market design for the cost-effective operation of variable, decentralised generation, and improving the market as the catalyst for investments by removing regulatory failures and market imperfections. In a nutshell, markets will need to:

(a) be more focused on short-term trading, including cross-border trading, to allow electricity from wind and solar energy to effectively compete in the market;

(b) link wholesale and retail markets to increase the flexibility of the system, let consumers benefit from times of cheap electricity, let them engage in demand response systems and produce electricity themselves; and,

(c) become even better at generating investment signals – as a matter of principle, it should be the market through its price signals triggering investments.

In this context, the present impact assessment investigates a number of options that improve market functioning by removing market distortions between different types of generation, that render the market's operation more flexible and adapted to the cost-effective operation of variable generation and improving the conditions for the participation of decentralised, flexible resources, such as demand and storage, into the market. Moreover, it investigates various means to improve price signals inciting investment in the right resources and location and investments in infrastructure.

The enhanced market design will improve the viability of RES E investments, but electricity market revenues alone might not prove sufficient in attracting renewable investments in a timely manner and at the required scale to meet EU's 2030 targets.

The enhanced market design and the strengthened ETS will improve the viability of RES E investments, in particular through the following channels:

- Where the marginal producer is a fossil fired power plant, a higher carbon price translates into higher average wholesale prices. The existing surplus of allowances is expected to decrease due to the implementation of the Market Stability Reserve and the higher Linear Reduction Factor, reducing the current imbalance between supply and demand for allowances;
- Greater system flexibility will be critical for a better integration of RES E in the system, reducing their hours of curtailment and the related forgone revenues; improving overall system flexibility is equally essential to limit the merit-order effect[335] and thus in avoiding the erosion of the market value of RES E produced electricity[336]
- The revision of priority dispatch rules and the better functioning of the short-term markets will strongly reduce (even eliminate according to the analysis) the occurrence of negative prices – leading again to higher average wholesale prices (especially during the hours with significant variable RES E generation);
- Improved market rules for intraday and balancing markets will increase their liquidity and allow access to those markets for all resources, thus helping RES E generators reduce their balancing costs;
- Removing existing (explicit or implicit) restrictions for the participation of all resources to the reserve and ancillary services markets will allow RES E to generate additional revenues from these markets.
- Price signals reflecting the actual value of electricity at each point of time, as well as the value of flexibility, will help ensure that flexible capacity is properly rewarded, channelling investment into such capacities or prevent its decommissioning.

With technology costs gradually reducing, ETS price increasing and the electricity market prices better reflecting the value of electricity, RES E investments in the electricity market will gradually become more and more market-based, reflecting the balance of supply and demand for the coming years and the associated costs to each technology.

The present impact assessment and the one on the RED II thus jointly come to the conclusion that the improved electricity market, in conjunction with a revised ETS could, under these conditions, deliver investments in the most mature renewable technologies (such as solar PV and onshore wind).

However, despite best efforts in market integration, electricity market revenues alone might not prove sufficient in attracting renewable investments in a timely manner and at the required scale to meet EU's 2030 targets. This investment gap is analysed in more details in the RES II

[335] Also referred occasionally as the 'cannibalisation effect'.

[336] The inherent variability of wind exposure and solar radiation affects the price that variable renewable electricity generators receive on the market (market value). During windy and sunny days the additional electricity supply reduces the prices. Because the drop is larger with more installed capacity, the market value of variable renewable electricity falls with higher penetration rate, translating into a gap to the average market value of all electricity generators over a given period (See Hirth, Lion, "*The Market Value of Variable Renewables"*, Energy Policy, Volume 38, 2013, p. 218-236)

impact assessment. The analysis shows that the picture is dynamic, with the enhanced market design and the strengthened ETS gradually and increasingly improving RES E profitability over the 2021-2030 period. At the beginning of the period, over-capacity, low ETS and wholesale market prices and still high RES E technology costs, make the case for investments in RES E technologies more difficult. However, an increasing ETS price, a more flexible and dynamic electricity market, technology costs reductions and adjustments in capacity increasingly facilitate investments over this period[337].

The impact assessment for RED II concludes that over the period 2021-2030 around half of the additional RES E capacity will still need some kind of support, but with significant decrease in the number of investments needing support towards 2030.

In particular, less mature RES E technologies, such as off-shore wind, will likely need some form of support throughout the 2021-2030 period. These technologies are required if RES E technologies are to be deployed to the extent required for meeting the 2030 and 2050 energy and climate objectives, and provide an important basis for the long-term competitiveness of an energy system based on RES E.

The picture also depends on regions. RES E technologies are more easily financed from the market in the regions with the highest potential (*e.g.* onshore wind in the Nordic region or solar in Southern Europe), while RES E continue to largely require support in the British Isles and in Central Europe.

Additionally, it should be noted that the speed at which RES E parity[338] is reached, in addition to the successful implementation of the MDI and ETS, also depends on factors that lay outside of the scope of these initiatives, including: (i) continued decrease in technology costs for RES E as well as complementary technologies (e.g. storage); (ii) the availability of (reasonably cheap) capital, which is a function of many variables, including project-specific and RES E framework-specific risks, but also general country risk; (iii) continued social acceptance; (iv) sufficiently high and stable fossil fuel prices.

<u>The need for a framework for RES E support schemes</u>

In order to address the risks associated with investments in RES E and the chance of failing to meet EU's 2030 target for RES, the MDI and the RED II impact assessments jointly consider that electricity market and ETS policies need to be complemented by an improved policy framework on RES E support schemes.

Against this background, the RED II impact assessment investigates options to ensure that, if and where support is needed, support is only applied where needed in a manner that is: (i) cost-effective and kept to a minimum, and (ii) creates as little distortions as possible to the

338 i.e. the moment when LCOE decreases to the level of the actual market value of the asset to be financed.

functioning of electricity markets, and to competition between technologies and between Member States. Indeed, the market can only deliver the full benefits sketched above, if policies fostering RES E are compatible with the market environment in which they operate.

In particular, the RED II impact assessment suggests creating a common European framework for support schemes. The framework would be effective as it would define design principles (i) that ensure sufficient investor certainty over the 2021-2030 and (ii) require the use (where needed) of market-based and cost-effective schemes based on emerging best practice design (including principles that are not covered by the current State Aid guidelines).

At the same time, the framework would be proportionate by leaving actual implementation to the State Aid guidelines (e.g. for the definition of thresholds applicable for any foreseen exemptions) and, most importantly, to the case by case, evidence-based, in-depth assessment of individual schemes by the services of DG Competition .Importantly, the framework would enshrine in legislation and expand the requirement to tender support; it would define tender design principles, based on emerging best practice, to ensure the highest cost-efficiency gains and to ensure market incentives are least distorted by the support mechanism.

The framework would thus strengthen the use of tenders as a natural phase-out mechanism for support, by which a competitive bidding process determines the remaining level of support required to bridge any financing gap – such level of support being expected to disappear for the most mature technologies over the course of the 2021-2030 period.

The importance of a framework for RES E support schemes for the present initiative.

It is also important to note that the progressive reform of RES E support schemes as proposed by the RED II initiative, building on the EEAG, is a prerequisite for the results of the present initiative to come about. In order to ensure that a market can function, it is necessary that market participants are progressively exposed to the same price signals and risks. Support schemes based on feed-in-tariffs prevent this and would need to be phased-out, with limited exemptions, and replaced by schemes that expose RES E to price signals, as for instance premium based schemes. This would be further supported by setting aid-levels through auctioning as RES E investment projects will then be incentivised to develop business models that optimise market-based returns[339].

How different types of CMs might affect RES E remuneration in the market

In market-wide, volume-based CMs, assets are remunerated if they can respond to specific technical performance criteria (i.e. in practice if they are dispatchable). Hence, it is likely that variable RES E producers (wind and solar) cannot participate in such schemes to the same extent as dispatchable generators. As the introduction of a market-wide volume-based scheme might render scarcity-based pricing less effective, RES E producers might receive less income then they would otherwise be able to earn on energy-only markets. A well-designed strategic reserve (provided it is activated (only at value of lost load and activated as a measure of last

[339] See also Annex IV for more information for information on the robustness on

resort (see above)), is less likely to have a negative impact on market revenues for intermittent RES E, as such a scheme relies on commodity price signals only and does not interact with scarcity-based pricing.

6.2.6.4.Level and volatility of wholesale prices

The analysis performed using all three models (METIS, PRIMES/IEM, PRIMES/OM) confirms that the projected investments in low carbon technologies, combined with increased demand response participation, are not expected to lead to the collapse of the wholesale market prices in the short and medium term. Although there will be hours with low (or even negative) prices, the wholesale prices will most probably be set by the marginal thermal generation technology during most hours of the year. Table 21 presents the distribution of wholesale prices in 2030, assessed for the various options of Problem Area I with PRIMES/IEM. Results indicate that the wholesale prices will fluctuate, but within reasonable limits on an EU level[340].

Table 21: Distribution of load weighted day-ahead market prices[341] in 2030

Day-ahead price in 2030 (EUR/MWh)	**Number of Hours**			
	Option 0	**Option 1(a)**	**Option 1(b)**	**Option 1(c)**
	Baseline	Level playing field	Strengthening short-term markets	Fully integrated markets
Below 60	0	0	84	0
Between 60-80	0	0	1155	1572
Between 80-90	2482	2642	2394	3169
Between 90-100	3254	3290	2870	3121
Between 100-110	2197	2013	1288	484
Between 110-120	372	555	528	0
Between 120-140	455	260	88	150
Above 140	0	0	353	264

Source: NTUA Modelling (PRIMES/IEM)

The above results do indicate that the improved market design will lead to more volatile average hourly prices, partly due to the introduction of locational signals which reveal the

340 Certain Member States though with very high RES E shares, like Spain and Portugal, and limited interconnections are expected to have significantly more volatile wholesale prices than other Member States.

341 Reported results reflected assumed bidding behaviour of generators. The behaviour was relatively conservative, reflecting though a stable condition in the market and the effects of competition (though market power was considered). The most important assumption driving these results is that plants bid above marginal costs and the hydro plants bid at opportunity costs. Minimum price observed (on EU28 level) was not lower than 60 EUR/MWh, highest price did not exceed 200 EUR/MWh. There were higher and lower prices on Member State level.

different value of electricity in the various nodes. This volatility though will be fairly restricted and will not be the result of extreme price fluctuations between zero and VoLL. The observed price ranges will be fairly constrained, as long as the share of variable RES E remains within certain limits[342]. When the share of RES E, and specifically of variable RES E technologies, exceeds these rough limits though, price volatility may increase significantly if other resources like storage are not in place yet to absorb a large part of it.

As can be seen in the table below, in 2050 the share of RES E is projected to approach 60%. In this case the spread between the baseload and peak load prices increases significantly, mainly due to the lower baseload prices compared to the previous periods. The average day-ahead market prices though remain high throughout the projection horizon, as thermal generation is still expected to be marginal (thus setting the day-ahead market price) during most hours of the year.

Table 22: Average wholesale prices and RES E Shares

	2020	2025	2030	2035	2040	2045	2050
Average wholesale market prices[343] (EUR 13/MWh)							
Average day-ahead market prices	74	95	103	118	115	135	122
baseload	74	83	93	98	89	108	71
mid-merit	74	95	103	118	116	137	122
peak load	93	98	137	135	134	149	138
Spread between average baseload and peak load SMP	19	15	44	38	45	41	67
Share of RES E in net electricity generation (%)							
Share of variable RES E	30.8	36.0	40.4	43.0	49.6	53.2	57.5
Solar	4.8	7.7	8.9	9.4	9.9	11.1	13.6
Wind	14.4	17.0	20.4	22.7	29.3	32.1	34.1

Source: NTUA modelling (PRIMES/OM)

342 A study by METIS finds that as long as the share of solar generation is lower than 10-12% of total electricity generation, solar production coincides with periods of high power demand and tends to smooth-out residual demand over the day, which is expected to lead to less variable prices. This changes though considerably for higher shares of solar. On the other hand, wind energy is directly related to variability and is a significant driver for flexibility needs. "*METIS Study S7: The role and need of flexibility in 2030. Focus on Energy Storage*", Artelys (2016).

343 Based on the modelling methodology followed, described in Annex IV, reported wholesale prices reflect the level of electricity prices which would lead to the recovery of the full costs of generators only via the wholesale market, on a plant by plant basis and over the lifetime of each asset in the case of an Energy only Market (i.e. Option 1). This modelling context differs significantly from the current one, characterised by different underlying market conditions (overcapacity, low fuel prices, distorted markets etc). See also Box 9 in Section 6.2.6.4 for a further discussion on this topic.

6.3. Impact Assessment for problem Area III (reinforce coordination between Member States for preventing and managing crisis situations)

6.3.1. Methodological Approach

In this section the impacts of the different policy options are identified and assessed. The options proposed should first and foremost be effective in improving trust of Member States to rely on neighbours' electricity markets in times of system stress. They should also lead to a more effective functioning of markets, with less undue market distortions. Additionally, reinforced coordination and cooperation between Member States in the identification and mitigation of risks and the management of crisis have also been identified as specific objectives.

The methodological approach followed for this analysis is mostly qualitative; however some quantitative analysis is provided as well, notably via the METIS simulations.

As regards the impacts, given the administrative nature of the measures and the objectives pursued, the most relevant impacts in terms of magnitude are the **economic** impacts.

The measures proposed (e.g. enhanced regional coordination and information exchange) anticipates a very limited impact, if any, on the **environment.** Therefore, the assessment does not examine the impact of the proposed measures on the environment.

6.3.2. Impacts of Policy Option 1 (Common minimum rules to be implemented by Member States)

6.3.2.1.Economic impacts

Overall, the policy tools proposed under this option should have positive effects. Putting in place a more common approach to crisis prevention and management would not entail additional costs for businesses and consumers. It would, by contrast, bring clear benefits to them.

First, a more common approach would help better prevent blackout situations, which are extremely costly. The immense costs of large-scale blackouts provide an indication of potential benefits of improved preparation and prevention[344].

[344] Previous blackouts in Europe had severe consequences. For example, the blackout in Italy in September 2003 resulted in a power disruption for several hours affecting about 55 million people in Italy and neighbouring countries and causing around 1.2 billion euros worth of damage. (source: *The costs of blackouts in Europe* (2016), EC CORDIS: http://cordis.europa.eu/news/rcn/132674_en.html).

Table 23: Overview over most severe blackouts in Europe

Country & year	Number of end-consumers interrupted	Duration, energy not served	Estimated costs to whole society
Sweden/Denmark, 2003	0.86 million (Sweden); 2.4 million (Denmark)	2.1 hours, 18 GWh	EUR 145 – 180 million
France, 1999	1.4 - 3.5 million	2 days–2 weeks, 400 GWh	EUR 11.5 billion
Italy/Switzerland, 2003	55 million	18 hours	
Sweden, 2005	0.7 million	1 day – 5 weeks, 11 GWh	EUR 400 million
Central Europe, 2006	45 million	Less than 2 hours	

Source: SESAME: Securing the European Electricity Supply Against Malicious and Accidental Threats

A more common approach to emergency handling, with an obligation for Member States to help each other, would help to avoid or limit the effects of potential blackouts. A more common approach, with clear obligations to e.g., follow up on the results of seasonal outlooks, would also reduce the costs of remedial actions TSOs have to face today. This, in turn, should have a positive effect with a reduction of costs overall.

In addition, improving transparency and information exchange would facilitate coordination, leading to a more efficient and less costly measures.

By ensuring that electricity markets operate as long as possible also in stress situations, cost-efficient measures to prevent and resolve crisis are prioritized.

6.3.2.2.Who would be affected and how

Option 1 is expected to have a positive effect on society at large and electricity consumers in particular, since it helps prevent crisis situations and avoid unnecessary cut-offs. Given the nature of the measures proposed, no major other impact on market participants and consumers is expected.

On cybersecurity, given the voluntary approach of this option, several stakeholders (TSOs, DSOs, generators, suppliers and aggregators) could be affected, as long as they implement the guidance proposed. However, the impact is estimated limited as the costs of cybersecurity for regulated entities merely need to get considered and taken into account by the regulatory authority. Thus, the TSOs and DSOs affected could recover their costs via grid tariffs. In that case, the pass through of costs would have an impact on consumers that could see a slightly increased in the final prices of electricity.

6.3.2.3.Impact on businesses and public authorities

The preparation of risk preparedness plans as well as the increased transparency and information exchange in crisis management imply a certain administrative effort[345]. However, the impact in terms of administrative impact would remain low, as currently Member States already assess risks relating to security of supply, and all have plans in place for dealing with electricity crisis situations[346].

In addition, it is foreseen to withdraw the current legal obligation for Member States to draw up reports monitoring security of supply[347], as such reporting obligation will no longer be necessary where national plans reflect a common approach and are made transparent. This would reduce administrative impacts.

6.3.3. Impacts of Policy Option 2 (Common minimum rules to be implemented by Member States plus regional co-operation)

6.3.3.1.Economic impacts

This option would lead to better preparedness for crisis situations at a lesser cost through enhanced regional coordination. The results of METIS simulations[348] show that well integrated markets and regional coordination during periods of extreme weather conditions (i.e. very low temperature[349]) are crucial in addressing the hours of system stress (i.e. hours of extreme electricity demand), and minimizing the probability of loss of load (interruption of electricity supply).

Most importantly, while a national level approach to security of supply disregards the contribution of neighboring countries in resolving a crisis situation, a regional approach to security of supply results in a better utilization of power plants and more likely avoidance of loss of load. This is due to the combined effect of the following three factors: (i) the variability of renewable production is partly smoothed out when one considers large geographical scales, (ii) the demands of different countries tend to peak at different times, and (iii) the power supply mix of different countries can be quite different, leading to synergies in their utilization.

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345 Administrative costs are defined as the costs incurred by enterprises, the voluntary sector, public authorities and citizens in meeting legal obligations to provide information on their action or production, either to public authorities or to private parties.

346 See *Risk Preparedness Study*.

347 Article 4 of the *Electricity Directive*; Article 7 of the *Electricity SoS Directive*.

348 *"METIS Study S16: Weather-driven revenue uncertainty for power producers and ways to mitigate it"*, Artelys (2016).

349 Even though periods with very low temperature occur rarely (9C difference between the 50 year worst case and the 1% centile) countries can face high demand peaks (e.g. Nordic countries and France) mainly due to the high consumption for the electric heating. As example, the additional demand for the 50 years peak compared to the annual peak demand is 23% for France, 18% for Sweden and 17.3% for Finland.

The following table compares the security of supply indicator, EENS, assessed by METIS for the three levels of coordination (national, regional, European)[350]. It highlights the highest value of the loss of load (electricity non-served expressed as percentage of annual load) when it is measured in a scenario of non-coordinated approach, which does not take into account the potential mutual assistance between countries. When cooperation takes place among Member States, the percentage of electricity non-served significantly decreases.

Table 24 - Global expected energy non-served as part of global demand within the three approaches for scenario ENTSO-E 2030 v1 with CCGT/OCGT current generation capacities

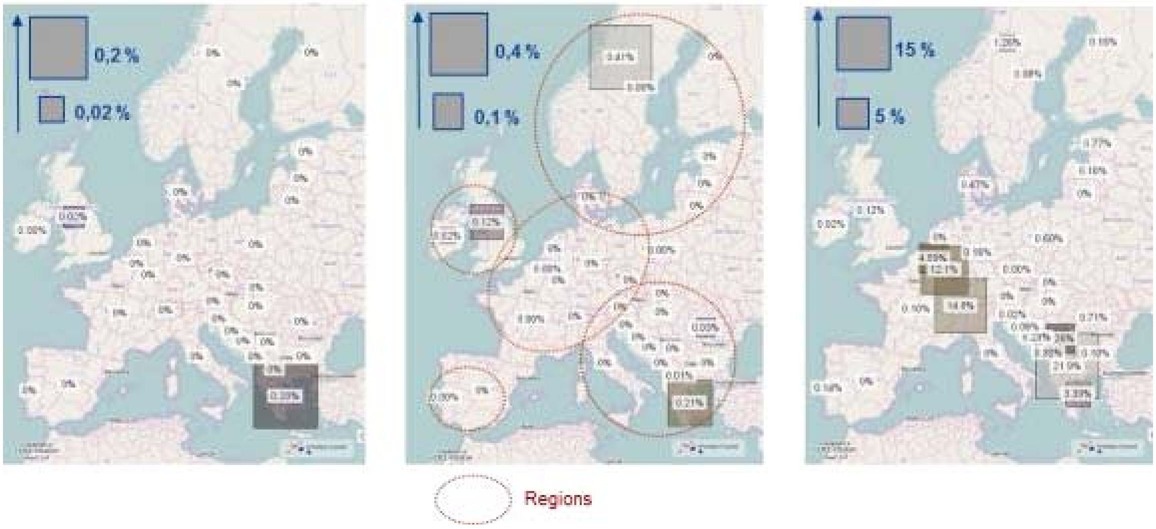
Level	EENS (% of annual load) – ENTSO-E V1 scenario
National level	0,36 %
Regional level	0,02 %
European level	0,01 %

ENTSO-E 2030 v1: vision for 2030 "Slowest progress". The perspective of Vision 1 is a scenario where no common European decision regarding how to reach the CO_2-emission reductions has been reached. Each country has its own policy and methodology for CO2, RES and resource adequacy.
Source: METIS

The EENS for the three levels of coordination are represented on the figure below. When the security of supply is assessed at the national level, many countries of central Europe seem to present substantial levels of loss of load. However, since these countries are interconnected, a regional assessment of security of supply (taking into account power exchanges within this region) significantly decreases the loss of load levels.

[350] *"METIS Study S04: Stakes of a common approach for generation and system adequacy"*, Artelys (2016).

Figure 14 - EENS (%) estimation by country for scenario ENTSO-E 2030 v1 with CCGT/OCGT current generation capacities. From left to right: EENS estimated at European, regional and national levels



CCGT: Combined Cycle Gas Turbine OCGT: Open Cycle Gas Turbine
ENTSO-E 2030 v1: vision for 2030 "Slowest progress". The perspective of Vision 1 is a scenario where no common European decision regarding how to reach the CO_2-emission reductions has been reached. Each country has its own policy and methodology for CO2, RES and resource adequacy.
Source: METIS

METIS simulations also show that thanks to regional cooperation the stress situations would decrease and concentrate in a limited number of hours that may occur simultaneously[351]. Therefore, it highlights the need for specific rules on how Member States should proceed in these particular circumstances, as proposed in this Option 2.

As the overall cost of the system would decrease thanks to enhanced coordination this could have a positive impact on prices for consumers.

On the contrary, a lack of coordination on how to prevent and manage crisis situations would imply significant opportunity costs. A recent study also evidenced that the integration of the European electricity market could deliver significant benefits of EUR 12.5 to 40 billion until 2030. However, this amount would be reduced by EUR 3 to 7.5 billion when Member States pursue security of electricity supply objectives following going alone approaches[352].

6.3.3.2.Who would be affected and how

As in the case for Option 1, Option 2 is expected to have a positive effect on society at large and electricity consumers in particular, since it helps prevent crisis situations and avoid

[351] Please also see in *Annexes to the Impact Assessment: Assessment of the Measures Associated with the Main Option*: Graphs 1 and 2 in *"6. Detailed measures assessed under problem area 3: a new legal framework for preventing and managing crises situations"*.

[352] *Benefits of an Integrated European Energy Market* (2013), BOOZ&CO.

unnecessary cut-offs. Given that, under Option 2, Member States would be required to effectively cooperate, and tools would be in place to monitor security of supply via the Electricity Coordination Group, such crisis prevention and management would be even more effective.

The measures would also have a positive effect on the business community, as there would be much more transparency and comparability as regards how Member States prepare for and intend to manage crisis situations. This will increase legal certainty for investors, power generators, power exchanges but also for TSOs when managing short-term crisis situations.

Among the stakeholders the most affected would be the competent authorities (e.g. Ministry, NRA) as actors responsible for the preparation of the risk preparedness plans (see below, assessment of impacts on public authorities).

6.3.3.3.Impact on businesses and public authorities

The assessment of this option shows a limited increase in administrative impact, although it would be to some extent higher than Option 1, given that national authorities would be required to pre-agree part of their risk preparedness plans in a regional context.

However, existing experiences show that a more regional approach to risk assessment and risk preparedness is technically and legally feasible. Further, since the regional parts of the plans would in practice be prepared by regional co-ordination centres between TSOs, the overall impact on Member States' administrations in terms of 'extra burdens' would be limited, and be clearly offset by the advantages such co-operation would bring in practice.[353]

In addition, more regional cooperation would also allow Member States to create synergies, to learn from each other, and jointly develop best practices. This should, overtime, lead to a reduction in administrative impacts.

Finally, European actors such as the Commission and ENTSO-E would provide guidance and facilitate the process of risk preparation and management. This would also help reduce impacts on Member States.

It should be noted, that under Option 2 (as is the case for Option 1) no new body or new reporting obligation is being created, and that existing obligations are being streamlined. Thus, the Electricity Coordination Group is an existing body meeting regularly, for the future it is foreseen to make this group more effective by giving it concrete tasks. Further, national reporting obligations would be reduced (e.g. repealing the obligation of Article 4 of Electricity Directive) and EU-level reporting would take place within the context of existing reports and existing reporting obligations (e.g. ACER annual report Monitoring the Internal Electricity and Natural Gas Markets).

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[353] The Nordic TSOs, regulators and energy authorities cooperate through *NordBER*, the Nordic Contingency and Crisis Management Forum. This includes information exchange and joint working groups and contingency planning for the overall Nordic power sector as a supplement to the national emergency work and TSO cooperation (www.nordber.org).

6.3.4. Impacts of Policy Option 3 (Full harmonisation and full decision-making at regional level)

6.3.4.1.Economic impacts

The regional coordination through the regional plans would have a positive impact in term of cost as the number of plans would be necessary less than twenty-eight plans and limited to the number of regions. In addition, the coordination at European level would decrease slightly the loss of load level compared to the regional coordination (EENS 0.01% compared to 0.02%).

On the contrary, on cybersecurity, the creation of a dedicated agency at EU level would have important economic implications as this agency would be a new body that does not exist yet and which is also not foreseen in the NIS Directive. The costs of creating this new agency are not only limited to the creation of a new agency itself, but the costs would also have to include the roll-out of a whole security infrastructure. For example, the estimated costs of putting in place the necessary security infrastructure and related services to establish a comparable national body - cross-sectorial governmental Computer Emergency Response Team ("**CERT**") with the similar duties and responsibilities at national level as the planned pan-European sector-specific agency - would be approximately EUR 2.5 million[354] per national body. This means that the costs for the security infrastructure would be manifold for a pan-European body. In terms of human resources, for the proper functioning of the new agency with minimum scope and tasks at EU level, it is estimated a staff of 168 full time equivalents (considering 6 full time equivalents per Member State sent to the EU agency). The representation from all Member States in the agency is essential in order to ensure trust and confidence on the institution. However, the availability of network and information security experts who are also well-versed in the energy sector is limited.

6.3.4.2.Who would be affected and how

The obligation of regional plans would have important implications for the competent authorities as the coordination and agreement of common issues (e.g. load shedding plan, harmonised definition of protected customers) would be a lengthy and complex process.

On cybersecurity, the creation of the new agency at EU level would mobilize highly qualified human resources with skills in both energy and information and communication technologies. This could have a potential impact on national administrations and energy companies as long as some of the experts in the field could be recruited by the new institution. However, the impact would be limited as the representation for all Member States should be guaranteed. Therefore, a small number of experts (around 6) per country could be recruited.

354 *"Impact Assessment accompanying the document Proposal for a Directive of the European Parliament and of the Council Concerning measures to ensure a high level of network and information security across the Union"*. SWD(2013) 32 final.

6.3.4.3.Impact on businesses and public authorities

Overall Option 3 would imply significantly administrative impact in the preparation of the regional plans. It would require important efforts to gather information related to national and regional circumstances and contribute to the joint task of assessing the risks and identifying the measures to be included in the plans. In any case, it would seem difficult to coordinate within a region the national specificities and risks originate mostly in one Member State.

The creation of a new agency on cybersecurity would imply significant administrative impacts in the preparation and set-up of the agency, as well as in the communication structure with already existing cross-sectorial bodies of Member States (CERTs/ Computer Security Incident Response Teams "CSIRTs").

6.4. Impact Assessment for Problem Area IV (Increase competition in the retail market)

6.4.1. Methodological Approach

This section compares the costs and benefits of each of the policy options to address this Problem Area in a semi-quantitative manner.

No data or methodology exists that would allow us to accurately quantify all the benefits of the measures examined.

However, this section draws on behavioural experiments from a controlled environment to evaluate the impact of some policy options on consumer decision-making. Where economic impacts cannot be quantified, quantitative desktop research and case studies are used to inform estimates of the extent of possible impacts, as well as possible winners and losers. Where appropriate, this section aims to illustrate the possible direct benefit to consumers assuming certain conditions. Implementation costs in terms of the impact on businesses and public authorities were estimated using the standard cost model for estimating administrative costs. And finally, this section also highlights important qualitative evidence that policymakers should also incorporate into their analysis of costs and benefits.

6.4.2. Impacts of Policy Option 0+ (Non-regulatory approach to improving competition and consumer engagement)

6.4.2.1.Economic Impacts

Option 0+ would lead to an estimated EUR 415 million in benefits to consumers for the period 2020-2030, which come as a result of an enforcement drive to tackle the switching costs currently faced by an estimated 4% of all EU electricity consumers that do not comply with EU law[355].

[355] See Annex 7.4, Section 7.4.5.

Other unquantifiable economic benefits include improved retail level competition resulting from the phase-out of regulated prices in some Member States[356], and more comparison tools that comply with the Unfair Commercial Practices Directive[357].

In addition, one may expect modest, indirect improvements to the health and well-being of energy poor consumers from the exchange of good practices stemming from the activities of the EU Observatory for energy poverty[358].

In spite of these considerations, it is unlikely that Option 0+ (Non-regulatory approach) would most effectively address the problems identified.

First, this option does not address the poor data flow between retail market actors that constitutes both a barrier to entry and a barrier to higher levels of service to consumers. Whereas Option 0+ is non-regulatory, a credible policy to tackle conflicts of interest among market actors around data handling would require a legislative intervention.

Secondly, as a non-regulatory option, the effectiveness of Option 0+ is significantly limited by shortcomings in the existing legislation. This significantly reduces the ability to address contract termination fees (which are currently legal under EU law), the partial availability of comparison websites in Member States, as well as energy poverty, which the current legislation does not require Member States to measure, and hence address it.

And finally, a non-regulatory approach to tackling price-regulation may lead to a fragmented regulatory framework across the EU given: (i) the uncertainty that surrounds the Commission's ability to convince hold-out Member States to voluntarily cease excessive regulatory interventions in price-setting; and (ii) the uncertainty that surrounds the success of any subsequent legal measures to infringe Member States on the issue.

6.4.2.2.Who would be affected and how

Consumers will benefit from more easily being able to compare offers in the market, as well as lower financial barriers to switching. Whilst consumer prices may rise in Member States phasing out price regulation, this would be offset by higher levels of service and the greater availability of value added products on the market.

Member States will benefit from a clearer understanding and measurement of energy poverty will have indirect positive impacts on **energy poor consumers**.

Suppliers would benefit from increased access to the market of any Member State phasing out price regulation. However, certain suppliers would also face tougher competition and increased pressure on margins as the result of the modestly greater consumer engagement expected.

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[356] See Annex 7.2, Section 7.2.5.
[357] See Annex 7.5, Section 7.5.5.
[358] See Annex 7.1, Section 7.1.5.

Any increase in consumer switching would increase the administrative impacts to **DSOs**. However, these costs would be passed through to end consumers.

NRAs in any Member States phasing out price regulation will need to significantly step up efforts to monitor the market, ensure efficient competition, and guarantee consumer protection. They will need to more closely monitor and report the number of disconnections. However, this may be offset by a reduction in price setting interventions, and increased competition resulting from greater consumer engagement.

6.4.2.3.Impact on businesses and public authorities

Option 0+ (Non-regulatory approach) would lead to quantifiable implementation costs of around EUR 0.9 million for the period 2020-2030, all resulting from setting up and running an EU Observatory for energy poverty[359]. It is anticipated that the soft law and enforcement measures associated with making better use of the existing legislation on regulated prices, switching fees and comparison tools would not result in significant additional costs compared with a business as usual scenario.

6.4.3. Impacts of Policy Option 1 (Flexible legislation addressing all problem drivers)

6.4.3.1.Economic Impacts

Option 1 would lead to an estimated EUR 2.2 billion in direct benefits to consumers for the period 2020-2030, which come as a result of: (i) reducing the switching-related charges faced by 21% of household electricity consumers, and so helping them realize the potentially significant gains of moving to a cheaper tariff[360]; (ii) further improvements to the switching rate for both electricity and gas household consumers as a result of the improved availability of price comparison tools[361]; (iii) an improved ability for consumers to identify the best offer in the market through improved access to information on the bill (although the gains of this latter intervention are not easy to quantify compared for instance with interventions aimed at making switching less costly for consumers)[362].

Other unquantifiable economic benefits include significantly improved retail competition resulting from the definitive phase-out of blanket price regulation in the 17 Member States still practicing it[363]. The impact of phasing out price regulation on retail price levels is impossible to quantify. However, the evidence strongly suggests it will lead to higher levels of consumer satisfaction. Indeed, even the energy component of retail bills does increase slightly in the short-term, consumer surplus (the difference between the price of the service and the price a consumer would be willing to pay for that service) may actually increase too as a result of the better service levels consumers receive in the non-regulated market. In

[359] The Commission secured funding to set up the Observatory for the period 2016-2019. The costs included in the Impact Assessment refer to the running annual cost to continue operating the Observatory. See Annex 7.4, Table 11 and Section 7.1.5.
[360] See Annex 7.4, Section 7.4.5.
[361] See Annex 7.6, Section 7.6.5.
[362] See Annex 7.4, Section 7.4.5.
[363] See Annex 7.2, Section 7.2.5.

addition, retail price competition is an important prerequisite for new services that would increase system flexibility (benefits examined in Section 6.1.4), and should lead to lower system costs that are passed through to consumers in both the energy and network components of bills in the longer term.

Non-discriminatory access to consumer data and nationally harmonized data formats will also help new suppliers and service providers to enter the market and develop innovative new products, resulting in further competition benefits and facilitating the transition to a more flexible electricity system[364].

Greater consumer engagement will also drive retail competition improvements, as competitive suppliers and service providers find it easier to take market share from less competitive alternatives. Other benefits come in terms of the higher levels of service electricity consumers can expect from more efficient data handling, and greater consumer awareness of the market and their own energy situation.

In addition, one may expect improvements in the targeting of measures to tackle energy poverty. Better measurement of the number of households on energy poverty will allow Member States and the EU to design better policies and exchange good practices. A generic definition of energy poverty in the legislation will clarify the concept of energy poverty, improving the functioning of the current provision and further helping knowledge dissemination and synergies across EU policies in energy efficiency and consumer protection.

6.4.3.2.Who would be affected and how

Consumers will benefit significantly from more easily being able to compare offers in the market, as well as lower financial barriers to switching. Whilst consumer prices may rise in the Member States phasing out price regulation, this would be offset by higher levels of service and the greater availability of value added products on the market. Consumers would also benefit from increased competition and higher levels of service resulting from rules that ensure quick and non-discriminatory access to data.

Box 8: Impacts on different groups of consumers

The benefits of the vast majority of the measures contained in the preferred options in Problem Areas I, II and III would manifest through lower system costs and greater system reliability, and therefore accrue to all consumers in an even manner. However, most of the measures contained in the preferred option of Problem Area IV, above, would benefit certain kinds of consumers more than others.

For example, whereas energy poor households would be the chief beneficiaries of new obligations to measure energy poverty levels, the marginally increased burdens of these obligations would be socialized amongst other ratepayers/taxpayers. In addition, whereas phasing out price regulation would free public finances to better protect households who qualify for targeted social support measures (i.e. vulnerable and/or energy poor consumers),

[364] See Annex 7.3, and *"Policies for DSOs, Distribution Tariffs and Data Handling"* (2016) Copenhagen Economics, and VVA.

the biggest losers from this policy would be high-volume, often higher-income consumers who have hitherto benefitted from retail prices that have been set at artificially low levels. Both these measures can therefore be considered progressive in nature i.e. they tend to redistribute surplus from relatively high-income ratepayers/taxpayers in order to increase the welfare of lower-income ratepayers.

The measures on switching-related fees and comparison tools would predominantly benefit consumers who are engaged in the market i.e. those who compare offers and/or switch regularly. Whilst the measures would also increase consumer engagement levels, and whilst the increased competition engendered by the measures would lead to more competitive offers on the market, disengaged consumers, including consumers who may be vulnerable, will not reap as many direct benefits.

And finally, the benefits of the billing measures would accrue predominantly to consumers who do not engage in the market or better control their energy consumption because of insufficient billing information or confusing bills. This may include a varied range of consumers, including certain vulnerable consumers, or those who are time poor.

Many **Member States** will benefit from a clearer understanding of energy poverty, which will have indirect positive impacts on **energy poor consumers**. However, Member States will also need to collect and report more information on energy poverty as a result of requirements in this option.

Suppliers would benefit from increased access to the market of the Member States phasing out price regulation. New entrants and **energy service companies** offering innovative products would also benefit from quick and non-discriminatory access to data. However, suppliers would also likely face increased pressure on margins as the result of the modestly greater consumer engagement expected. Certain suppliers may need to adjust contractual conditions and reformat their consumer bills in order to comply with new requirements on contract termination fees and billing information. And they would likely also bear the brunt of the significant costs to protect energy poor consumers.

As **TSOs and DSOs** are normally the market actors charged with data management, they would be the most affected by the new data management requirements – particularly the DSOs who currently fall below the unbundling threshold as they would need to implement further measures to ensure non-discriminatory data handling. Any increase in consumer switching would also increase the administrative impacts to **DSOs**. However, all these costs would be passed through to end consumers. In addition, network operators would benefit from the anticipated entrance of aggregators and other energy service companies who facilitate network flexibility, as a result of non-discriminatory data flows.

NRAs in the 17 Member States phasing out price regulation will need to significantly step up efforts to monitor the market, ensure efficient competition, and guarantee consumer protection. However, these impacts may be offset by increased consumer engagement, which would naturally foster competition in the market.

6.4.3.3.Impact on businesses and public authorities

It is estimated that implementing the consumer-related elements of Option 1 (Flexible legislation) would lead to quantifiable costs of between EUR 21 million and EUR 24 million for the period 2020-2030. These would mainly stem from national authorities having to set up and run certification schemes for energy comparison tools or an independently run energy comparison tool themselves[365]. However, many suppliers would also bear costs associated with modifying their consumer bills to comply with the modest requirements in this option[366]. Unquantifiable impacts come in the form of the reduced contractual freedom that suppliers have, which is associated with the restriction on contract termination fees for certain kinds of contracts only[367].

Implementing the energy poverty provisions in Option 1 (Flexible legislation) would result in quantifiable costs of EUR 2.3 million for the period 2020-2030. These primarily result from measuring energy poverty making reference to household income and household energy expenditure using data already collected by Member States[368].

Significant, albeit unquantifiable costs are associated with creating a level playing field for access to data in Option 1 (Flexible legislation). In particular, ensuring that Member States implement a standardised data format at the national level will significantly impact many market actors (suppliers, DSOs, third parties such as energy service companies, data administrators), who would have to redesign their IT systems to accommodate this format. However, these costs will be mitigated by the fact that measures can be applied independently of the data management model that each Member State has chosen. This reduces the potentially very significant scope for sunk costs if Member States were to all conform to a common data management model[369].

6.4.4. Impacts of Policy Option 2 (Harmonization and extensive safeguards for consumers addressing all problem drivers)

6.4.4.1.Economic Impacts

Option 2 (Harmonization and extensive safeguards) could lead up to up to EUR 3.5 billion in direct benefits to consumers for the period 2020-2030, which come as a result of: (i) an outright ban on all switching-related charges[370]; (ii) further improvements to the switching rate as a result of every Member State establishing a government (funded) price comparison tool guaranteed to work in the consumer's interest[371]; (iii) an improved ability for consumers to identify the best offer in the market through fully standardised billing information[372].

However, there is greater uncertainty surrounding the benefits that stem from these interventions. Whilst an outright ban on all switching-related charges would increase the financial incentive to switch, it could also make it more difficult to finance certain energy

365 See Annex 7.5, Section 7.5.5.
366 See Annex 7.6, Section 7.6.5.
367 See Annex 7.4, Section 7.4.5.
368 See Annex 7.1, Section 7.1.5 and Table 16.
369 See Annex 7.3, and "*Policies for DSOs, Distribution Tariffs and Data Handling"* Copenhagen Economics, and VVA (2016).
370 See Annex 7.4, Section 7.4.5.
371 See Annex 7.5, Section 7.5.5.
372 See Annex 7.6, Section 7.6.5.

service investments (i.e. solar panels or energy efficiency upgrades packaged with energy supply contracts) if implemented poorly. It might also result in a smaller range of tariffs available to consumers. Not all government (funded) price comparison tools may work better for consumers than the comparison tools already available on the market. And it may be difficult, if not impossible, to devise a standard EU bill design that accommodates differences in consumer preferences and market conditions in all Member States.

Whilst phasing-out blanket price regulation in the 17 Member States still practicing it would lead to improved retail competition, defining the conditions under which price regulation could continue at the EU level would be problematic. In particular, permitting price regulation for households who consume below a certain price threshold would not accurately target those most in need of assistance. In addition, permitting regulators to only set price caps above cost would be difficult to enforce due to opaque cost structures. It also risks holding back investments in product innovation and service quality, which require higher margins[373]. As with Option 1 (Flexible legislation), the impact of phasing out price regulation on retail price levels is impossible to quantify, whereas the evidence strongly suggests it will lead to higher levels of consumer satisfaction.

Defining a specific EU data management model for all Member States, such as an independent central data hub, would bring similar benefits to Option 1 in terms of helping new suppliers and service providers to enter the market. In addition, it would be easier to enforce at the EU level[374].

6.4.4.2.Who would be affected and how

Consumers will benefit from more easily being able to compare offers in the market, as well as lower financial barriers to switching. However, these gains may be tempered by a reduction in the availability of beneficial products on the market. Whilst consumer prices may rise in the Member States phasing out price regulation, this would be offset by higher levels of service and the greater availability of value added products on the market. Consumers would also benefit from increased competition and higher levels of service resulting from rules that ensure quick and non-discriminatory access to data.

Energy poor consumers in many Member States would enjoy significant benefits from the comprehensive set of disconnection safeguards outlined as they are more likely to be on risk of disconnection. Whilst many **Member States** will benefit from a prescriptive EU definition of energy poverty and from better information on the energy efficiency of the housing stock, the benefits of better measurement may not composite for the significant resources required to survey the housing stock at national level. Energy poor and vulnerable consumers may also be impacted by more poorly targeted support as the result of permissible instances of price setting being defined at the EU-level, rather than being assessed on a case by case basis.

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[373] See Annex 7.2, Section 7.2.5.

[374] See Annex 7.3, and *"Policies for DSOs, Distribution Tariffs and Data Handling"* Copenhagen Economics, and VVA (2016)

Suppliers would benefit from increased access to the market of the Member States phasing out price regulation. However, all suppliers would need to significantly reformat their bills in order to comply with a standard EU bill design. They would likely also bear the brunt of the very significant costs to protect energy poor consumers introduced under Option 2 (Harmonization and extensive safeguards) – in particular the complete ban on winter disconnections. However, new entrants and **energy service companies** offering innovative products would benefit from quick and non-discriminatory access to data.

As **TSOs and DSOs** are normally the market actors charged with data management, they would be the most affected by the requirement to establish a standard EU data management model that all Member States. Indeed, since many would incur significant sunk costs in adopting a model different from their own, the impacts could be significant. However, all these costs would be passed through to end consumers. In addition, network operators would benefit from the anticipated entrance of aggregators and other energy service companies who facilitate network flexibility, as a result of non-discriminatory data flows.

NRAs in the 17 Member States phasing out price regulation will need to significantly step up efforts to monitor the market, ensure efficient competition, and guarantee consumer protection. However, these impacts may be offset by increased consumer engagement, which would naturally foster competition in the market.

6.4.4.3. Impact on businesses and public authorities

It is estimated that implementing the consumer-related elements of Option 2 ((Harmonization and extensive safeguards) would lead to quantifiable costs of between EUR 42 million and EUR 51 million for the period 2020-2030. These would mainly stem from national authorities having to set up and run energy comparison tools[375], and energy suppliers having to heavily modify their consumer bills to comply with the requirements in this option[376]. Unquantifiable impacts come in the form of the greatly reduced contractual freedom that suppliers have, which is associated with the ban on contract termination fees[377].

Implementing the energy poverty provisions in Option 2 (Harmonization and extensive safeguards) would result in quantifiable costs of between EUR 1.2 billion and EUR 3.8 billion for the period 2020-2030. Unless public authorities step in, these costs would most likely fall on suppliers and result from: (i) the additional costs of unpaid bills resulting from the requirement for suppliers to give all customers a disconnection notice of at least two months; (ii) the additional costs of unpaid bills resulting from the cessation of winter disconnections; and (iii) refinancing costs resulting from the obligation to offer all consumers the possibility to delay payments or restructure their debt prior to disconnection[378].

As these costs associated with disconnection safeguards are large, it is likely that this option would result in distortions to competition in Member States where the public does not cover

[375] See Annex 7.5, Section 7.5.5.
[376] See Annex 7.6, Section 7.6.5.
[377] See Annex 7.4, Section 7.4.5.
[378] See Annex 7.1, Section 7.1.5 and Table 24.

these costs. Whilst suppliers active in such markets could raise margins to socialize losses from unpaid bills, certain suppliers – especially smaller ones who are less well equipped to deal with the additional pressure on their operations – may seek to avoid entering markets where there are likely to be significant risks of disconnections.

Member States may be better suited to design these schemes to ensure that synergies between national social services and disconnection safeguards are achieved. These synergies may also result in public sector savings which may be significant given the substantial costs of these measures and the overlap between social policy and disconnections for non-payment.

Very significant costs are associated with creating a level playing field for access to data in Option 2 (Harmonization and extensive safeguards). A mandatory data handling model will imply the administrative costs of defining and designing such a model, and more importantly high sunk costs for existing data models and additional costs for rebuilding a new one, both in terms of personnel costs and IT infrastructure. Designing and building a new data handling model is a complex procedure and may well take several years of planning and implementation. For example, in Denmark alone, the central data hub took more than 4 years to design and develop in its simple form, and 7 years in its enhanced form, and is estimated to a cost of approximately EUR 165 million, where approximately EUR 65 million accrued to the data hub administrator (the TSO), and around EUR 100 million accrued to DSOs and energy suppliers[379].

6.4.5. Environmental impacts

The legislative options examined above – Option 1 (Flexible legislation) and Option 2 (Harmonization and extensive safeguards) – can each be expected to have significant, albeit indirect, environmental benefits because they enable the uptake of technologies that help the electricity system become more flexible, thus enabling higher levels of variable and decentralized RES E penetration. Non-discriminatory access to consumer data and a phase-out of regulated prices will allow new entrants and energy service companies to develop and offer value-added products such as dynamic price supply contracts, incentive-based demand response services, green tariffs, and supply contracts with bundled energy efficiency or rooftop solar investments. In addition, tackling the barriers to consumer engagement will increase the selective pressure for such new services. The measures will benefit smaller consumers in particular, the group of market actors which the analysis has shown represents the greatest remaining source of low hanging fruit in terms of system flexibility potential.

In addition, phasing out blanket price regulation – particularly in Member States with very low margins – will help address the high levels of electricity and gas consumption caused by artificially low prices. This will make it easier to achieve climate objectives and provide a proper price signal for energy efficiency investments.

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379 See Annex 7.3, and *"Policies for DSOs, Distribution Tariffs and Data Handling"* Copenhagen Economics, and VVA (2016).

6.4.6. Impacts on fundamental rights regarding data protection

A key building block for the completion of the Digital Single Market and the Energy Union includes strong and efficient protection of fundamental rights in a developing digital environment. The proposed policy measures on data management were developed in this context, to ensure widespread access and use of digital technologies while at the same time guaranteeing a high level of the right to private life and to the protection of personal data as enshrined in Articles 7 and 8 of the Charter of Fundamental Rights of the EU.

As data on individual consumers' consumption and billing become central to the deployment of distributed energy resources and the development of new flexibility services, the measures on data management in the various policy options proposed (from compliance with data protection legislation and the Third Energy Package - Option 0 (Baseline); to further introduction of specific requirements on data handling responsibilities based on principles of transparency and non-discrimination – Option 1 (Flexible legislation); and implementation of a specific data management model to be described in EU legislation – Option 2 (Harmonization and extensive consumer safeguards)) seek to ensure the impartiality of the entity which handles data and to ensure uniform rules under which data can be shared. Indeed, consumers must be reassured that their consumption and metering data remain under their control. Access to a consumer's metering or billing details can only happen when authorised by that consumer and under the condition that the personal data protection and privacy are guaranteed.

In this light, the data management policy options are therefore fully aligned and further substantiate the fundamental rights to privacy and protection of personal data of Articles 7 and 8 of the Charter of Fundamental Rights of the EU, as well as with the General Data Protection Regulation and with the Commission Recommendation on the Data Protection Impact Assessment Template for Smart Grid and Smart Metering Environments.

Box 9: External factors and the assessment of the impacts

Price signals and long-term confidence that costs can be recovered in reasonable payback times are essential ingredients for a well-functioning market. In a market which is not distorted by external costs and interventions, the level and variability of the spot price on the wholesale market, plays a role in signalling the need for investments in new resources. With external costs and in the absence of the right short- and long-term price signals, it is more likely that inappropriate investment or divestment decisions are taken, i.e. too-late decisions or technology choices that turn out to be inefficient in the long run. It also renders it more likely that capacity exits that is valuable for the system as a whole.

The impact assessment demonstrates that an improved market design can lead to a much more efficient utilisation of resources and establish the market as a main driver of investments in generation assets (even if only progressively and not fully for all RES E technologies (See Box 7)). This will be mainly driven by the restoration of the economic merit order curve (see Section 6.1.2, Figure 11) and the improved reflection of scarcity in short term electricity prices (see Section 6.2.6.4, Table 21), both resulting from the measures proposed by the current initiative, combined with the exit of non-economical units as a result of the transition towards a market equilibrium (See section 6.2.6.3, Table 18) from the current overcapacity.

Market exit should be brought about by market forces and the initiative generally aims at removing existing obstacles to this in regulation. Market exit is framed to some degree by the measures proposed under Problem Area II. The extent to which a system with capacity remuneration exacerbate or not existing excess capacity depends on how the capacity requirement is set within the mechanism. If the system is correctly calibrated by means of a genuine resource adequacy assessment (See Problem Area II, Option 2) there will be no overcapacities. This is both important to ensure that CMs do not incite lower than economically optimal wholesale prices, which would inhibit investments, and prevent delays upon the transition path by preventing exit of non-essential resources. Moreover, the measures under Problem Area I and Problem Area II, option I, will ensure that prices better reflect the real value of electricity, affecting specifically the remuneration of electricity generation units that operate less often but provide security and flexibility to the system. For the same reason, it is important that TSOs (as responsible entities for overall operation of the system) define and remunerate ancillary services appropriately, remunerating generators for the full range of services they provide. These market improvements affect exit in the sense that they ensure that only those resources will exit that genuinely have no value for the system as a whole.

It is true that overall price developments in the electricity sector will also depend on cost factors beyond the present initiative, such as the carbon prices, prices for primary fuels or technological costs.

These external factors would mainly impact the level of wholesale prices[380], possibly affecting to a certain extent the overall level of benefits to be expected from the present initiative or their distribution among individual options (in manners which are not easily predictable in view of the many interactions that take place). However, such changes are not expected to affect the order of preferred options. Indeed, the proposed measures in essence derive their benefits from the removal of current market distortions and imperfections, while at the same time having comparably small implementation costs. These are benefits that are inherent to the measures themselves and do not depend on the precise context in which they are implemented. Moreover, strong synergies exist between the sets of options within the package (See Section 7.5.1), meaning that the overall benefits of a given option are more affected by the coherence of the package as a whole, than by its interactions with factors outside the present initiative.

Low wholesale prices though would affect investments in electricity resources such as demand response, RES E and peaking plant investments. Concerning demand response, the aim of the initiative is to offer to the consumers the opportunity to participate in the market if they wish to, either directly (e.g. industrial consumers) or indirectly (e.g. via aggregators). The initiative is not aiming to affect the level and variability of wholesale prices, but to make the functioning of the markets more efficient so that it can deliver price signals reflecting the value of electricity at each moment of time and the need for future investments (and in what type). Although persistent low electricity wholesale prices could lead to low investments, this

[380] For example the prices projected by PRIMES/OM tend to be quite higher even in 2020 compared to the currently observed market prices. Several reasons contribute to this: (a) fuel costs are projected to increase by 25% for gas and coal, (b) demand increases, (c) few new investments take place (mainly RES to reach the 2020 target); this point combined with demand increase described above , make it the first step in reducing the currently observed overcapacity, (d) a well-functioning EoM without distortions is assumed, (e) scarcity bidding is assumed, in the sense that there is a mark-up on the bids so that generators can recover their full costs only from the market in the long-run.

is a normal outcome if it is a result of market dynamics and not distortions. For example a system characterized by overcapacity should have low prices to signal that investments are not needed.

It is equally noteworthy that the modelling work (as presented in section 6.2.6.4) indicates that in the mid-long term, even in the presence of larger shares of variable RES E, conventional generators will set the marginal price in a sufficient number of hours to produce meaningful price signals to guide overall market operations. Increasing RES E penetration therefore does not necessarily give rise to low(er) average wholesale market prices.

The assessment of the benefits also depends to a certain degree on the progress made in the implementation of measures proposed by parallel initiatives, considered as part of the baseline for the present initiative, most notably the REDII. In this context, it is important to note that the assessment of the present initiative assumes the full phase-out of non-market based support mechanisms by 2030 for RES E, i.e. feed-in-tariffs would be phased-out and replaced by schemes that expose RES E to price signals, as for instance premium based schemes. Such investments would be further triggered by setting support-levels through auctioning as RES E investments projects would then be incentivised to develop business models that optimise market based returns. These are reasonable assumptions in view of the rules that are expected to be in place well before 2030 (see in particular Annex IV).

The success or failure to implement such measures for RES E in time would have a direct impact on the effectiveness of the present initiative. A partial or delayed implementation of the closely associated policies, as proposed in the revised Renewable Energy Directive, especially if combined with the prolongation of existing distortions, would reduce the efficiency of the market design initiative in the medium term and postpone its expected benefits further into the future. On the contrary, an expedient implementation would achieve the establishment of efficient markets and the delivery of the associated benefits sooner.

6.5. Social impacts

European social partner's joint position[381]:

"Citizens and especially low-income households should be able to pay their bills"

The new market design should be: *"ensuring that the provision of electricity is secure, safe, reliable and reasonably priced"*

It was also underlines that: *"workers in and outside of the electricity sector are relying on a stable electricity market for their jobs. There is currently a precarious situation for many workers in the electricity sector, especially among power plant workers. Many plants are not* *adequately remunerated for the services they provide (e.g. flexibility, security of supply) and therefore several companies foresee closure. Workers could lose their jobs".*

A shown above, more efficiently organised cross-border electricity markets can avoid significant costs for energy customers. Given the importance of energy costs for many companies and for individual households, realising the possible cost savings can be expected to improve competitiveness of commercial players (with positive impact on jobs and growth) and on private customers (especially relevant for low-income households).

The electricity industry (i.e. production, transmission, distribution and trade of electricity) is a key economic sector with a turnover amounting to not less than EUR **1.182 billion** in 2014[382]. EU households spent **EUR 148.2 billion** on electricity bills (EUR 97.4 billion on gas), which means that every household had to pay **EUR 686,- per year for electricity** (EUR 451,- for gas) on average, with important variations between single Member States[383]. Especially for low-income households, costs for electricity can eat up large parts of the available income[384]. Also for many industries, especially those in competition at a world-wide scale, energy costs are an important factor for competitiveness. EU wholesale electricity prices are still higher than in other regions in the world (e.g. around 30% compared to the U.S.[385]). Avoiding unnecessary prices increases by an intelligent organisation of electricity markets (e.g. market-based solutions and using advantages of aggregation across borders) can therefore save jobs and create growth in the EU.

The possible measures analysed to better adapt the current market rules to decarbonised electricity markets through revised legislation (See options in **'Problem Area I'** e.g. re-establishing the level playing field, improving short-term markets and removing barriers for demand response and distributed resources) would allow to integrate electricity generated from RES E at lower costs. They would also increase the potential for cross-border trade, leading to more competition and better possibilities to level out production and demand differences across larger areas.

Grid fees and other system costs have increased in recent years due to the suboptimal organisation of markets, but also through the need to adapt the infrastructure to decentralised generation. Better organised electricity markets would therefore not only save costs for electricity, but also keep grid costs in check (e.g. by limiting the necessary costs for TSO-interventions to keep the grid stable, so-called 're-dispatching'[386]). Measures to keep the

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382 Eurostat Data for 2014.

383 Eurostat Data for 2014.

384 In 2014, EU households in the lowest income quintile spent an average of 9% of their household income on electricity and gas, whereas middle income households spent 6% on electricity and gas. Source: DG ENER Data.

385 See e.g. Communication on *"A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy"* of 25.2.2015 COM (2015), p.3.

386 See e.g. the estimations for Germany, where grid tariff component already exceeds the energy costs and where re-dispatching costs are estimated to grow to EUR 4 billion/year in the next years, see e.g. http://www.zfk.de/artikel/bis-zu-vier-milliarden-fuer-engpassmanagement-2023.html .

further expansion of grid fees in check can therefore bring tangible benefits to industry and private (low-income) customers[387].

The analysed measures to improve investors' certainty and limit state interventions (**'Problem Area II'**, e.g. better co-ordinating capacity mechanisms between countries) can also be expected to have a positive impact on competitiveness and on energy bills to of households. As shown above, fragmented adequacy planning and capacity mechanisms leads to higher energy costs and network charges. If each Member State builds its backup generation in its own country without taking into account generation from neighbours, this will necessarily lead to inefficiencies through unnecessary duplication of investments[388]. Notably Options 2 (regional adequacy assessment) and Option 3 (cross-border openness of capacity mechanisms) would help to keep the prices for state interventions concerning capacity mechanism in check. [389]

In a similar manner, the analysed measures to improve risk preparedness (**'Problem Area III'**, e.g. better co-ordinated planning and rules to better coordinate possible load shedding in case of crises) options are likely to have a positive impact for EU citizens and businesses. Previous blackouts have shown that even in the "traditional" electricity market with low shares of RES E so-called "cascade blackouts" resulting from problems in other Member States can seriously harm businesses and customers, in particular those depending on electrical heating (see on the system blackouts in 2003 and 2006 above, section 6.3.2.1). Amounts of variable RES E have increased ever since, and so has the importance of a reliable electricity grid for citizens and customers (e.g. increased risks of blackouts for internet-driven businesses and private communication). Minimising blackout risks through better regional coordination will therefore contribute to avoid negative impacts on businesses and households.

Finally, the analysed measures to enhance performance of retail markets (**Problem Area IV**, e.g. measures facilitating to change suppliers, more targeted support for "energy-poor") customers in the transition to market-based prices, etc.) will also have a positive impact on businesses and households. In addition, the proposals relative to the phasing out of regulated prices, should incentivise Member States which currently use blanket price regulation to provide targeted support for vulnerable and energy poor consumers instead of providing an indirect support to all consumers regardless of their circumstances as is currently often the case.

[387] According to the Commission's modelling, the assessed options under Problem Area I reduce the average cost of total demand, i.e. the cost of each MWh generated, apart from Option 1(a) (level playing field). More specifically and compared to the baseline, Option 1(a) (level playing field) increases it by 6%, while Options 1(b) (strengthening short-term markets), 1(c) (demand response/distributed resources) and Option 2 decrease it by 6%, 9% and 11%, respectively.

[388] See for further evidence on the disadvantages of fragmented CMs above, Problem Area II (investment uncertainty/fragmented CMs), discussion of Option 3.

[389] Option 4 (EU wide capacity market) is not considered here as it was already discarded above. However, it is useful to note that it would also be more costly (about 5% pursuant to the Commission's model) than the other options.

Improvements to the health[390] and well-being of energy poor consumers, savings to the health sector[391], and economy-wide productivity gains[392] can be expected from the packages of energy poverty measures evaluated above. Due to the indirect nature of the way these measures would address energy poverty, and a lack of specific data on their impact, these benefits are impossible to quantify.

Health impacts most commonly associated with energy poverty and under-heated dwellings can be fatal, resulting in higher mortality during winter period. Benefits of effective action to reduce excess winter mortality could be substantial given the scale of the issue. In fact independent research shows that over 200,000 excess winter deaths have occurred across 11 Western European countries alone[393] during the winter of 2014/2015. In addition to the physical impacts, cold homes are directly related to mental health problems.

The energy transition and decarbonisation policies play a key role in developing Europe's competitive edge internationally as growth and jobs increasingly will have to come from innovative products and services which are closely linked to sustainable and smart solutions. Recent studies on the impact of EU's energy and climate targets suggest a net increase in job demand in the power generation market as a result of the transition of the energy system. One factor behind this is the higher labour intensity in power generation from renewable sources compared to gas or nuclear. There will also be a change in the employment structure as many of the jobs associated with the energy transition require higher skills and increased supply of workers that outweigh job losses in somewhat less qualified jobs in conventional energy generation. The total number of jobs in the power sector (operation, maintenance, construction, installation, and manufacturing) is forecast to increase by around a half by 2030[394]. Further positive impacts are expected in the indirect and substitution effects. [395] Whereas these effects are related to the energy transition as such and cannot be attributed solely to the measures assessed here, by ensuring a cost effective transition in more smoothly functioning markets, these beneficial social effects stand a much increased chance of being realised and retained.

[390] "*Fuel Poor & Health. Evidence work and evidence gaps. DECC. Presented at Health, cold homes and fuel poverty Seminar at the University of Ulster"*. 2015. Cole, E. Available at: http://nhfshare.heartforum.org.uk/HealthyPlaces/ESRCFuelPoverty/Cole.pdf; *"Towards an identification of European indoor environments' impact on health and performance - homes and schools.* 2014. Grün & Urlaub, *Excess winter mortality: a cross-country analysis identifying key risk factors. Journal of Epidemiology & Community Health"* 2003. Healy.

[391] "*2009 Annual Report of the Chief Medical Officer (London: Department of Health", 2010. Donaldson, L.*

[392] "*Indoor cold and mortality. In Environmental Burden of Disease Associated with Inadequate Housing", (Bonn: World Health Organisation (Regional office for Europe))*. 2011. Rudge, J.

[393] Excess mortality in Europe in the winter season 2014/15, EuroMOMO, source: http://www.euromomo.eu/methods/pdf/winter_season_summary_2015.pdf

[394] Between 2 and 2.5 million in 2030, depending on the decarbonisation scenario (source Neujobs/CEPS)

[395] Neujobs/CEPS report "*Impact on Decarbonisation of the Energy System on Employment in Europe*" 2015 , The methodology is based on applying "employment factors" (i.e. labour intensities) of different energy technologies to changing energy mixes as projected by the EU decarbonisation scenarios.

7. COMPARISON OF THE OPTIONS

Taking into account the impacts of the options and the assessment presented in Section 6, the following section compares the different options against each other using, the baseline scenario as the reference and applying the following criteria:

- Effectiveness: the options proposed should first and foremost be effective and thus be suitable to addressing the specified problem;
- Efficiency: this criterion assesses the extent to which objectives can be achieved at the least cost (benefits versus the costs).

The tables provide a summary of the assessment of the policy options against these criteria. The options are measures against the criteria applied for the assessment of the impacts specified for options developed to address each Problem Area (See Sections 6.1, 6.2, 6.3 and 6.4 respectively) and the comparison of the options below. Each policy option is rated between "---" (very negative), 0 (neutral) and "+++" (very positive).

The options are not compared here on the basis of their coherence with parallel initiatives. The design of the baseline already assures that all option are compatible with parallel initiatives. In particular, the baseline in the present impact assessment ensures that under all investigated options, the RES E targets (as well as other policy targets) are met. Consequently, comparing options on the basis of their compatibility with the RED II initiative is meaningless.

7.1. Comparison of options for adapting market design for the cost-effective operation of variable and often decentralised generation, taking into account technological developments

All options, except for Option 0 (baseline scenario) can contribute to achieving to a degree the objective of adapting the market design to make it suitable for the cost-effective operation of variable, often decentralised generation of electricity and capture some of the potential social welfare and environmental opportunities (e.g. lower wholesale electricity prices; incentivise the increase of low carbon electricity generation). However, the effectiveness and efficiency of the different options, as well as their impact, vary significantly.

Table 25: Summary of assessment of policy options

Criteria → --------- Options ↓	Effectiveness	Efficiency	Impacts		
			Economic impact	Impact on stakeholders	Impact on business and public authorities
Policy Option 0 (Baseline)	0	0	0	0	0
Policy Option 1(a) (level playing field)	+	+	+	-	-
Policy Option 1(b) (strengthening short-term markets)	++	++	++	--	--
Policy Option 1(c) (demand response/ distributed resources)	+++	++	+++	--	--
Policy Option 2 (fully integrated markets)	+++	+++	++	---	---

Source: DG ENER

In summary:

Option 0 (baseline scenario): will fall short in providing for the adaptation of the market design to the new realities of the interconnected electricity system and will not allow the internal electricity market to reach its full potential.

Options 1(a) (level playing field), 1(b) (strengthening short-term markets) and 1(c) (demand response/distributed resources) reflect an increasing degree of ambition regarding the integration of the national electricity markets, with Option 1(c) building on the packages of measures covered under Options 1(a) and 1(b) and including additional measures. All these options present a compromise between bottom-up initiatives and top-down steering of the market development, without substituting the role of national governments, regulators and TSOs by a centralised and fully harmonised system. Option 1(a) and Option 1(b) are significantly more efficient than Option 0 but cannot be expected to fully meet the specific objectives, given that these options do not cover measures for including additional resources (i.e., demand response, distributed RES E and storage) in the electricity markets to further increase the flexibility of the electricity system and the resources for the TSOs to manage it. The value of these additional resources for the efficient operation of decarbonised electricity markets and hence for the energy transition should not be underestimated. Option 1(c) provides a more holistic, effective and efficient package of solutions and has the added value that it will not lead to significant additional impacts on stakeholders or on businesses and public authorities. Indeed, while Option 1(c) may lead to additional administrative impacts for Member States and competent authorities regarding the implementation and monitoring of the measures, these impacts will be offset by lower barriers to entry to start-ups and SMEs, by the benefits to market parties from more stable regulatory frameworks and new business opportunities as well as by the benefits to consumers from more competition and access to wider choice.

As regards Option 2 (fully integrated market), while having advantages in terms of lower coordination requirements (i.e., a fully integrated EU-market can be operated more efficiently), the results of the assessment indicate that the move towards a more integrated European approach has less significant economic added value since most of the benefits will have already been reaped under the regional, more decentralised approach under Option 1(c) (demand response/distributed resources). Moreover, Option 2 (fully integrated market) has the disadvantage of requiring significant changes to established practices, systems and processes and hence a significant impact on stakeholders, businesses, Member States and competent authorities. Such profound changes of national competences in favour of centralised powers "across the board" would also raise serious questions concerning the subsidiarity of the measure. Therefore, in view that for Option 2 (fully integrated market) the efficiency gains are not significantly higher compared to Option 1(c) (demand response/distributed resources) but the impacts and required changes to national competences much greater, it appears disproportionate and not the most appropriate option at the current stage of development of the internal electricity market.

In the light of the previous assessment, the preferred option would be Option 1(c) (pulling demand response and distributed resources in the market) (which encompasses Options 1(a) (level playing field) and 1(b) (strengthening short-term markets). This option is the best in terms of effectiveness and, given its impacts, has been demonstrated to be the most efficient as well as consistent with other policy areas.

This preferred Option has large support among stakeholders. No support exists for retaining the status quo (i.e. Option 0 or 0+) whereas Option 2 (fully integrated market) was generally deemed a step too far. It is noted that hesitations by stakeholders on aspects of the preferred option, such as the removal of priority dispatch provisions under Option 1(a) (level playing field), are based on the notion that this should go hand in hand with a reform rendering the market more adapted to RES E resources, which is what is foreseen under Option 1(b) (strengthening short-term markets) and Option 1(c) (demand response/distributed resources)[396].

7.2. Comparison of Options for facilitating investments in the right amount and in the right type of resources for the EU

All options, except for Option 0 (baseline scenario), can improve the overall cost-efficiency of the electricity sector and contribute towards achieving the objective of facilitating investments in the right amount and in the right type of resources for the EU. However, the effectiveness and efficiency of the different options, as well as their viability and impact, vary significantly.

[396] Reference is made to Section 5.1.1 through to 5.1.5 and Sections 7 of Annexes 1.1 through 3.4 for more detailed representations of stakeholders' opinions.

Table 26: Summary of assessment of policy options

Criteria → --------- Options ↓	Effectiveness	Efficiency	Impacts		
			Economic impact	Impact on stakeholders	Impact on business and public authorities
Policy Option 0 (Baseline scenario)	0	0	0	0	0
Policy Option 1 (Reinforced energy-only market without CMs)	+	+	+	+/-	-
Policy Option 2 (reinforced energy-only market + EU adequacy assessment for CMs)	+	+	+	+	+
Policy Option 3 (reinforced energy-only market + EU adequacy assessment for CMs + EU framework on cross-border participation CMs)	++	++	++	++	++

Source: DG ENER

In summary:

Option 0 (baseline scenario), which would assume the existence of national capacity mechanisms without coordination at EU-level will fall short of achieving the specific objectives of improving market functioning to reduce the need to have recourse to state intervention and of ensuring that state-interventions, where needed, are more coordinated, efficient and compatible with the EU's internal energy market.

Option 1 (reinforced energy-only market without CMs) can improve the overall cost-efficiency of the electricity sector significantly. The analysis shows that undistorted energy-only markets increase overall system efficiency as make sure that resources are better utilized across the borders, demand can better participate in markets, and renewables can be better integrated into the system without additional need for subsidies. This will in turn decrease the need for capacity mechanisms (which are often introduced as a reaction to markets which do not produce correct price signals due to state interventions).

The analysis also shows that reinforced energy-only markets can in principle provide the right signals for market operation and ensure resource adequacy. Option 1 also has slightly more positive environmental impacts than any of the other options.

However, markets are still characterised by manifold regulatory distortions today, and removing the distortive effects will not be possible with immediate effects in many Member

States. The observation that undistorted markets can provide the necessary investment signals has therefore to be weighed against the observation that a significant transition time to phase out the existing distortions will be necessary. Furthermore, some national distortions (e.g. resulting from differences in taxation) cannot be addressed by a reform of energy law and are therefore likely to continue.

Investors also do not have perfect foresight of market conditions, and confidence that they will not be distorted for the economic lifetime of their investments. Such certainty is increasingly difficult to find, often due to uncertainty as to the regulatory measures that could be taken in the future that may supress prices and reduce the load factors of plants compared to the assumptions made when the investment decision is taken. In a market that requires more and more varied sources of funding that in many cases are competing with other, non-electricity, projects for capital, relying solely on the energy price as a basis for investment is not always easy. Uncertainty about future policy developments or the perception thereof can create 'missing money' that may require addressing[397].

The legislator should also take into account that the level of interconnection is markedly different among Member States. This militates for a more nuanced approach than a straightforward EU-wide prohibition of CMs.

In this perspective, not allowing Member States to introduce any type of CMs would mean that Member States would be prevented from addressing adequacy concerns with CMs. As those concerns might be legitimate, this option is not considered to be appropriate.

But, as developed in Chapter 2.2.1 undistorted energy price signals are fundamental irrespective of whether generators are solely relying on energy market incomes or also receive capacity payments. Therefore the measures aimed at removing distortions from energy-only markets discussed under Option 1 (e.g. scarcity pricing or reinforced locational signals) are 'no-regrets' and assumed as being integral parts of Options 2 (CMs + EU adequacy assessment) and 3 (CMs + EU framework on cross-border participation)..

When compared with the baseline, **Option 2** (CMs + EU adequacy assessment) can improve the overall cost-efficiency of the electricity sector as significant savings can be achieved through establishing an EU-wide approach to resource adequacy assessments as opposed to national-based adequacy assessments. At the same time Option 2 does not allow reaping the full benefits of cross-border participation in CMs.

Option 3 (CMs + EU framework on cross-border participation) (which includes the market reforms under Option 1 and the regional assessment under Option 2) goes beyond Option 2 as it proposes additional measures to avoid fragmentation of CMs. This would achieve significant additional net benefits when compared with Option 2. This is because it makes sure that foreign resource providers can effectively participate in national capacity mechanisms and avoids competition and market distortions resulting from capacity payments

[397] It must however also be recognised that CMs by themselves are not a panacea as they can equally be a source of regulatory uncertainty. Indeed, in practise CM designs are regularly found imperfect and consequently adjusted on a regular basis.

which are reserved to domestic participants. By remunerating foreign resources for their services this option reduces investment distortions that might be present in Option 2 as a result from uncoordinated approaches to cross-border participation.

In view of the assessment above, **Option 3** (CMs + EU framework on cross-border participation) **(encompassing options 1 and 2) is the preferred option.**

This preferred Option has large support among stakeholders. There is almost a consensus amongst stakeholders on the need for a more aligned method for generation adequacy assessment. A majority of stakeholders support the idea that any legitimate claim to introduce CMs should be based on a common methodology. When it comes to the geographical scope of the harmonised assessment, a vast majority of stakeholders call for regional or EU-wide adequacy assessments, while only a minority favour a national approach. There is also support for the idea to align adequacy standards across Member States. Stakeholders clearly support a common EU framework for cross-border participation in CMs[398].

Most stakeholders including Member States agree that a regional/ European framework for CMs is preferable. Member States, however, might want to keep a large degree of freedom when proposing a CM. They might claim that beyond a revamped regional/ EU generation adequacy assessment, there is legitimacy for a national assessment based on which they can claim the necessity of their CM. Similarly Member States might instinctively want to rely more on national assets and favour them over cross-border assets.

7.3. Comparison of options for improving Member States' reliance on each other in times of system stress and reinforcing coordination between Member States for preventing and managing crisis situations

All options, except for Option 0 (baseline scenario), can contribute to achieve the objective of improving Member State's reliance on each other in times of system stress and reinforcing their coordination and cooperation at times of crisis situation. However, the effectiveness and efficiency of the different options, as well as their viability and impact, vary significantly.

[398] Reference is made to Section 5.2.1 through to 5.2.9 and Sections 7 of Annexes 4.1 through 5.2 for more detailed representations of stakeholders' opinions.

Table 27: Summary of assessment of policy options

Criteria → --------- Options ↓	Effectiveness	Efficiency	Impacts		
			Economic impact	Impact on stakeholders	Impact on business and public authorities
Policy Option 0 (Baseline scenario)	0	0	0	0	0
Policy Option 1 (Common minimum EU rules)	++	++	+	+	0/-
Policy Option 2 (EU rules + regional cooperation)	+++	+++	++	++	0/-
Policy Option 3 (Full harmonisation)	+++	--	+	+	0/--

From the point of view of impacts, particularly costs and administrative impact, Option 1 (Common minimum EU rules) could in principle appear as preferred option. However, the performance in terms of effectiveness and efficiency is limited compared to Option 2 (EU rules + regional cooperation) and Option 3 (Full harmonisation). Additionally, impacts associated with Option 3 (Full harmonisation) are neither proportionate nor fully justified by the effectiveness of the solutions, which makes Option 3 (Full harmonisation) perform poorly in terms of efficiency compared to Option 2 (EU rules + regional cooperation).

Overall, the more harmonized approach to security of supply through minimum rules pursued by Option 1 (Common minimum EU rules) would not solve all the problems identified, in particular, the uncoordinated planning and preparation ahead of a crisis. As regards Option 1 (Common minimum EU rules), the main drawback of this approach is that each Member State would be drafting and adoption the national risk preparedness plans under its own responsibility. While the regionally coordinated plans with crisis scenarios identified at regional level and the agreement of some aspects of the plan (e.g. load shedding plan) in a regional context, aim at ensuring that all regional specificities are fully considered. Given the urgency to enhance the level of protection against cyber threats and vulnerabilities, it must be concluded that Option 1 (Common minimum EU rules) regarding cybersecurity is not recommended, because it is not viable for reaching the policy objectives, given that the effectiveness would depend on whether the voluntary approach would actually deliver a sufficient level of security.

Option 2 (EU rules + regional cooperation) addresses many of the shortcomings of Option 1 (Common minimum EU rules) providing a more effective package of solutions. In particular, the regionally coordinated plans ensure the regional identification of risks and the consistency of the measures for prevention and managing crisis situations. For cybersecurity this option creates a harmonised level of preparedness in the energy sector and ensures that all players have the same understanding of risks and that all operators of essential services follow the same selection criteria for the energy sector throughout Europe.

Overall, Option 3 (Full harmonisation) represents a highly intrusive approach that tries to address possible risks by resorting to a full harmonisation of principles and the prescription of concrete solutions. For example, the preparation of risk preparedness plans at regional level ensures full coherence of actions ahead and during a crisis. However, the major limitation is that national specificities could not be addressed through regional plans. The detailed "*emergency rulebook*" with an exhaustive list of measures would also reduce the room of manoeuvre of Member States to tackle local problems. The creation of a dedicated agency on cybersecurity at EU level would be also a costly solution. The assessment of impacts in Option 3 (Full harmonisation) shows that the estimated impact on cost is likely to be high and looking at the performance in terms of effectiveness, it makes Option 3 (Full harmonisation) a disproportionate and not very efficient option.

In the light of the previous assessment, the preferred option would be Option 2 (EU rules + regional cooperation). This option is the best in terms of effectiveness and, given its economic impacts, has been demonstrated to be the most efficient as well as consistent with other policy areas.

This preferred Option has large support among stakeholders. The majority of stakeholders are in favour of regional coordination of risk preparedness plans and ex-ante cross-border agreements to ensure that markets function as long as possible in crisis situations. No support exists for retaining the status quo (i.e. Option 0 or 0+), as stakeholders agree that the current framework does not offer sufficient guarantees that electricity crisis situations are properly prepared for and handled in Europe. Option 3 (Full harmonisation) was deemed a step too far; stakeholders did not support a fully harmonised approached based on rulebooks[399].

7.4. Comparison of options for addressing the causes and symptoms of weak competition in the energy retail market

Although there is a significant level of uncertainty in quantifying the benefits of the options in this Problem Area, all options, except for Option 0 (baseline scenario), are expected to improve retail competition. However, the anticipated effectiveness and efficiency of the different options vary markedly.

[399] Reference is made to Section 5.3.1 through to 5.3.6 and Section 6 of Annexes (6.1.4 presentation of options and 6.1.8 for more detailed representations of stakeholders' opinions).

Table 28: Summary of assessment of policy options

Criteria → --------- Options ↓	Effectiveness	Efficiency	Impacts		
			Economic impact	Impact on stakeholders	Implementation costs
Policy Option 0 (Baseline scenario)	0	0	0	0	0
Policy Option 0+ (Non-regulatory approach)	+	+++	+	+/0	-
Policy Option 1 (Flexible legislation)	+++	++	+++	+++/--	--
Policy Option 2 (Harmonization and extensive consumer safeguards)	+++ / ++	-	+++ / ++	++/---	---

Option 0+ (Non-regulatory approach) can be expected to lead to **modest, albeit tangible, economic benefits** primarily as a result of the voluntary phase-out of regulated prices in some Member States and the drive to tackle illegal switching costs. Given its **low implementation costs**, it is a **highly efficient** option. And the few stakeholders that will be affected will be affected positively. However, the **effectiveness of Option 0+ is significantly limited** by the fact that non-regulatory measures are not suitable for tackling the poor data flow between retail market actors that constitutes both a barrier to entry and a barrier to higher levels of service to consumers. In addition, shortcomings in the existing legislation make it impossible to significantly improve consumer engagement and energy poverty. They also introduce great uncertainty around the drive to phase out price regulation.

Option 1 (Flexible legislation) would probably lead to **substantial economic benefits**. Retail competition would be improved as a result of the definitive phase-out of blanket price regulation, non-discriminatory access to consumer data, and increased consumer engagement. In addition, consumers would see direct benefits through improved switching. And the energy poor would be better protected, leading to knock-on benefits to the broader economy. Given that Option 1 would entail **moderate implementation costs** (these stem primarily from ensuring a standardised format for consumer data, and the various burdens associated with improving consumer engagement) it is **an efficient option** as these costs are considerably outweighed by the benefits. Many stakeholder groupings are likely to be positively and negatively affected by the collection of policy measures in Option 1. But none would bear a disproportionate burden that would not be offset by commensurate benefits. Likewise, the proposed measures in Option 1 respect the principle and limits of subsidiarity.

Option 2 (Harmonization and extensive consumer safeguards) would also lead to **substantial economic benefits**, albeit with a **greater degree of uncertainty** over the size of these benefits. This uncertainty stems from the tension some of the measures in Option 2 may have with competition (stronger disconnection safeguards, an outright ban on all switching-related charges), and from the difficulty of prescribing EU-level solutions in certain areas (defining exceptions to price deregulation, implementing a standard EU bill design). Whilst a single EU data management model would be just as effective and easier to enforce, and whilst the energy poor would be even better protected by the stronger safeguards proposed, the **high**

implementation cost of these measures would **reduce the efficiency** of Option 2 compared with Option 1. Disconnection safeguards may be better designed by Member States to ensure synergies between national social services. As social policy is a primary competence of Member States, Option 2 may go beyond the boundaries of subsidiarity. Finally, many stakeholders will be affected by the collection of policy measures in Option 1, both positively and negatively. Suppliers and DSOs in particular would face significant burdens that they would at least partially pass on to consumers i.e. socialise.

In the light of the analysis, the preferred option is Option 1 (Flexible legislation). This option is most likely to be the most effective, is efficient, and is consistent with other policy areas.

Most stakeholders would support (or at least be indifferent to) the measures in preferred Option 1 (Flexible legislation). This is due to the fact that a flexible legislative approach allows the problems identified to be largely addressed while accommodating: 1) the broad range of national differences that still exist in retail markets for energy; and 2) the specific concerns aired in the stakeholder outreach. Nevertheless, some Member States practising blanket price regulation will likely oppose a phase out of this, and industry associations representing energy suppliers have stated that they would not welcome any EU legislation addressing the content of bills.

Almost no support exists for retaining the status quo (i.e. Option 0) or for tackling the issues in the Problem Area through soft law (Option 0+), except for isolated instances already mentioned. Several measures in Option 2 (Harmonization and extensive consumer safeguards) were generally deemed a step too far by a number of stakeholders, including stakeholders such as ACER, or NRAs who represent the interest of the public.[400]

7.5. Synergies, trade-offs between Problem Areas and sequencing

The measures considered in this impact assessment are highly complementary. Most of the different Options considered in each Problem Area would reinforce the effect of options in other Problem Areas, with little trade-offs between the different areas.

7.5.1. Synergies

The measures to make intraday and balancing markets more flexible such as pursued under Problem Area I, in particular Option 1(b) (strenghening short-term markets) and Problem Area II , Option 1 (reinforced energy-only market) will foster a price signal that better reflects the value of electricity, notably when it is scarce. It will hence provide a price signal benefical for flexible resources, in particular demand response and storage and improve the business case for innovative assets and service models to enter the market as assessed under Problem Area I Option 1(c) (demand response/distributed resources). It will also reinforce liquidity and competition in the electricity wholesale electricity markets. As choice on the wholesale

[400] See Section 5.4.2 through to 5.4.5, and Sections 7 of Annexes 7.1 through 7.6 for more detailed representations of stakeholders' opinions.

market is a pre-condition for more competition on retail markets, more liquid wholesale markets will also contribute to improving competition in retail markets (Problem Area VI).

Helping RES E resources to be remunerated through the market as fostered with the measures under Problem Area I will ultimately reduce the high level of taxes and levies currently necessary to drive RES E deployment, decreasing overall system costs and making energy more affordable compared with a scenario where markets remain poorly adapted to RES E.

The measures proposed to improve the functioning of the electricity markets as discussed under Problem Areas I and II, in particular Option 1 (reinforced energy market/No CMs), will also lead to a more robust formation of price signals. Robust price signals will reduce the need for assets to be remunerated by alternative revenue streams to be a credible investment opportunity or avoid its decommissioning and hence reduce the need for government intervention in the form of CMs or otherwise to ensure resource adequacy such as discussed under Problem Area II, Option 3. Moreover, the measures assessed Problem area II, in particular the preferred Option 3 will reduce market distorition caused by genuinly justifed CMs and improve the ability of the market to operate optimally. In other words, improving the energy markets will reduce the need for governement intervention to ensure investments in electricity resources.

Measures to improve retail competition, consumer engagement and data handling as fostered with the measures under Problem Area IV (Retail markets) will increase system flexibility as targeted by the measures under Problem Area I, in particuler Option 1(c) (pulling demand response and distributed resources into the market). This is because the majority of untapped demand response potential originates from smaller consumers and because retail price regulation can have a detrimental effect on the deployment of innovative consumer products such as dynamic price supply contracts.

Improving the market in its ability to renumerate (in particular, flexible) resources and removing the distortions that prevent resources to reacte to proper price signals (such as those aimed at in Problem I area I and Option 1 of Problem Area II) will overall improve the robustness of the system to satisfy demand at all times and, hence, the freqeuncy and overall number of hours that recourse has to be taken to out-of-market measures to operate the system, such as the demand curtailment, as discussed under Problem Area III (Crisis situations).

Phasing out price regulation as fostered with the measures under Problem Area IV (particularly in Member States with very low retail margins) will help address the high levels of electricity and gas consumption caused by artificially low prices and provide an accurate price signal for energy efficiency investments that would ultimately mitigate the effects of security of supply events as targeted by the measures under Problem Area III (Crisis situations). Removing price regulation will also allow for a more flexible organisation of the market and increase the incentives to participate in the market through demand response as fostered by the measures assessed un Problem Area I. Option 1(c) (pulling demand response and distributed resources into the market)

Measures to improve retail competition as discussed under Problems Area IV, will ensure that all benefits, including those expected under Problem Areas I, II and III are transferred to end-consumers, ultimately increasing the beneficial effects on social welfare and competiveness.

Overall, market improvement measures will address increasing energy poverty as discussed in Problem Area IV. Indeed, one of the three main drivers[401] of energy poverty has been the gradual increase in retail prices.

Measures to ensure a common approach to crisis prevention and management as is the objective under Problem Area III avoid unduly interventions in market functioning. Better preparedness, transparency and clear rules on crisis management will build trust between Member States to rely on the internal electicity market for resource adequacy, helping the achievement of the objectives under Problem Area II. By imposing obligations to cooperate and lend assistance, Member States are also less likely to "over-protect" themselves againt possible crisis situations.

7.5.2. Trade-offs

The mesures selected as the preferred option under Problem Area I and II are mutually reinforcing in that they collectively aim at improving market functioning, thereby reducing the need for market gouvernment intervention through CMs, and reducing their distortive effects if nonetheless required. However, scarcity pricing and CMs to a certain degree can be seen as alternative measures to foster investments. Even if CM deployment rules and design principles are ringfenced, the mere fact that resources are also renumerated by CMs means that the effectiveness of scarcity prices to drive investment may be reduced as the number of hours that scarcity occurs and thus the profits that more flexible resources can earn from selling energy in the market is reduced. It needs also to be noted that scarcity prices and CMs (at least in its market-wide version) act differently on investment decision in a crucial manner. Whereas such CMs rewards any capacity, removing barriers for scarcity pricing will improve remuneration of flexible capacity in particular.

The measures assessed under various options in the impact assessment seek to improve the overall flexibilty of the electricity system. However, they do this by employing different means. It can therefore be expected that some trade-offs exist between these options. Improvements in the usage of interconnection capacity (as assessed under Problem Area I, Option 1(b) (strenghening short-term markets)) allow a given plant to exploit variations in production and demand over a larger geographcial area allowing for a more stable intertemporal production pattern of the plant. Improving the usage of interconnection capacity will hence favour the usage of less flexible resources over flexible ones. Similarly, pulling demand response into the market will reduce the profits of generation capacity and, in particular, flexible generation capacity which may amplify the amount of capacity that needs to exit the market into the transition towards 2030. Ultimately, efficient markets should select the most cost-efficient solutions.

Energy poverty safeguards whose costs directly accrue to suppliers – particularly, the costly disconnection safeguards considered in Option 2 (Harmonization and extensive consumer safeguards) of Problem Area IV (Retail markets) – may act as a barrier to retail-level competition, and diminish the associated benefits to consumers, including lower prices, new

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401 The other two drivers being wage growth and the energy efficiency of housing stock

and innovative products, and higher levels of service. Although the implementation costs of these safeguards will be passed on to consumers, and therefore socialized, different energy suppliers may have different abilities to do this, and to deal with the additional consumer engagement costs. Some may therefore choose not to enter markets with such safeguards in place. A uniform level of such safeguards throughout the market would help create a level playing field and address such competition impacts.

7.5.3. Sequencing of measures

Over all, the synergies between the measures are large and the temporal dependency low, the overall beneficial effects will be achieved only if all measures are implemented as a package.

A sequencing of measures is not necessarily appropriate to establish at EU level. The judgement of moving to a next stage of market development much depends on the development stage of the electricity market at hand. The reality is that Member States are at different, sometimes even very different stages, in the development of their market arrangements. As an example only, as a result of the individual characteristics of national markets, the timing of the phase out of price regulation may differ on a case-by-case basis. This is to enable national authorities to ensure that the necessary prerequisites of a smooth transition are in place before all regulatory interventions in price setting are discontinued. Such prerequisites may include, for example, the number of suppliers in the market, the market share of the largest suppliers, or retail price levels. The same is true for other measures proposed.

The EU legislation ultimately adopted should therefore need to find the appropriate balance between setting out a well-defined endpoint whilst allowing sufficient space for Member States to manage their transition thereon.

8. MONITORING AND EVALUATION

8.1. Future monitoring and evaluation plan

The Commission will systematically monitor the transposition and compliance of the Member States and other actors with the finally adopted measures and take enforcement measures if and when required and report on the progress made in this regard on a regular basis. For this purpose, the Commission will be supported by ACER as described below.

In addition, as it has already done in the context of the implementation of the Third Package, the Commission will provide guidance documents providing assistance on the implementation of the adopted measures.

Parallel to the proposed initiatives, the Commission will bring forward an initiative concerning the governance of the Energy Union that will streamline the monitoring and reporting requirements. Based on the initiative of the governance of the Energy Union, the current monitoring and reporting requirements of Commission and Member States' reporting obligations in the Third Energy Package will be integrated in a horizontal monitoring report. More information on the streamlining of the monitoring and reporting requirements can be found in the impact assessment for the governance of the European Union.

The annual reporting by ACER and the evaluation by the Commission, together with the reporting from the Electricity Coordination Group are part of the proposed initiatives and described in the sections below.

8.2. Annual reporting by ACER and evaluation by the Commission

The monitoring of the proposed initiatives will be carried out following a two tier approach: annual reporting by ACER and an evaluation by the Commission.

8.2.1. Annual reporting by ACER

ACER's duties[402] under the Third Package include the monitoring of and reporting on the internal electricity market. ACER prepares and publishes an annual market monitoring report that tracks the progress of the integration process and the performance of electricity markets and identifies any barriers to the completion of the internal electricity retail and wholesale markets.

The sources of data on which ACER relies to compile its annual market monitoring report are: the Commission, NRAs, ENTSO-E, the Bureau Européen des Unions de Consommateurs (BEUC) and other relevant organisations. ACER's annual report is based on publicly available information and the information provided by these entities.

Based on the present proposals, ACER will continue to monitor and report on the internal electricity market on an annual basis after the adoption of the proposals. ACER's annual reporting will replace the Commission's reporting obligations that are currently still existing under the Electricity Directive. The present proposals also foresee extending ACER's monitoring mandate to include matters related to security of supply.

8.2.2. Evaluation by the Commission

The Commission will carry out a fully-fleged evaluation of the impact of the proposed initiatives, including the effectiveness, efficiency, continuing coherence and relevance of the proposals, within a given timeline after the entry into force of the adopted measures (indicatively, 5 years).

In the context of this evaluation, the Commission will pay particular attention as to whether the assumptions underlying its analyses in the present impact assessment were valid.

The evaluation report will be developed by the Commission with the assistance of external experts, on the basis of terms of reference developed by the Commission services. Stakeholders will be informed of and consulted on the evaluation report, and they will also be regularly informed of the progress of the evaluation and its findings. The evaluation report will be made public.

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[402] The legal basis for the Agency's market monitoring duties is in Article 11 of Regulation (EC) No. 713/2009. ACER equally monitors and reports on many more detailed aspects of the regulatory framework. (http://www.acer.europa.eu/Official_documents/Publications/Pages/Publication.aspx)

8.3. Monitoring by the Electricity Coordination Group

The Electricity Coordination Group will be also a tool to monitor developments in the internal electricity market and in particular as regards security of supply more closely. To this end a concrete mandate will be given to the Electricity Coordination Group, in particular to monitor the security of supply in the EU on the basis of a set of indicators (e.g. EENS, LoLE) and regular outlooks and reports produced by ENTSO-E[403].

8.4. Operational objectives

The key objective of the present initiative is to make electricity markets more secure, efficient and competitive whilst ensuring that electricity is generated in a sustainable way and remains affordable to all. The operational objectives for the preferred options are listed as follows:

Problem Area I (market design not fit for an increasing share of variable decentralised generation and technological developments):

- Adoption of measures directed at removing market distortions deriving from the different treatment to generation from different sources;
- Adoption of measures aiming at providing for liquid and better integrated short-term markets;
- Adoption of measures directed at removing barriers preventing demand response from participating in energy and reserve markets;
- Adoption of measures aiming at strengthening the role of ACER, clarifying the role of NRAs at regional level, criteria for enhancing ENTSO-E's transparency and monitoring obligations, rules for formalising the role of DSOs at European level.

Problem Area II (uncertainty about sufficient future generation investments and uncoordinated capacity markets):

- Adoption of measures aiming at improving the price signals of the electricity markets;
- Specific requirements to align national CMs by requiring ENTSO-E to propose a methodology for an EU-wide resource adequacy assessment and requiring Member States to rely on the assessment.
- Adoption of rules aiming at enhancing the compatibility between CMs.

Problem Area III (reinforce coordination between Member States for preventing and managing crisis situations):

- Adoption of measures aiming at improving risk assessment and preparedness;
- Adoption of rules aiming at improving coordination in emergency;
- Adoption of measures aiming at improving transparency and information sharing.

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403 See Preferred Option (Option 2 (EU rules + regional cooperation)) to address problem Area III (When preparing or managing crisis situations, Member States tend to disregard the situation across their borders).

Problem Area IV (retail markets):

- Adoption of measures aiming at reducing regulatory intervention in retail price setting;
- Adoption of measures aiming at protecting energy poor and vulnerable consumers;
- Adoption of measures directed at removing barriers to market entry for new supply and service companies;
- Adoption of measures aimed at increasing consumer engagement and choice.

8.5. Monitoring indicators and benchmarks

As of 2021, ACER will be invited to review its current monitoring indicators with a view to ensure their continuing relevance for monitoring progress towards the objectives underlying the present proposals. ACER will continue relying on the same sources of data used for the preparation of the market monitoring report. It will be tasked to cover in that report the security of supply dimension as well. Monitoring indicators could include:

Problem Area I (market design not fit for an increasing share of variable decentralised generation and technological developments):

- Indicators relating to market and regulatory barriers that affect the level playing field between market participant and types of resources, such as the degree of capacity dispatched - fully, partially or not at all - on the basis of price signals only, and the usage of market and non-market based curtailment;
- Indicators related to the degree of flexibility available within the electricity system and the development of intraday and balancing markets, such the level of market liquidity in intraday and balancing markets and the allocation and use of cross-border capacity for these time-frames, and related efficiency gains;
- Indicators related to the participation of distributed resources and demand in the market (including use from system operators), energy service operators such as aggregators and barriers to market participation. Such for example, the capacity and production by distributed RES E and storage, the capacity of demand response available and its activation, the number of facilities and their capacity operated by aggregators;
- Indicators related to consumer access to smart metring systems, their functionalities and availability/uptake of dynamic electricity pricing contracts;
- Indicators related to the evaluation of the performance by ACER, ENTSO-E and NRAs of their duties.

Problem Area II (uncertainty about sufficient future generation investments and uncoordinated capacity markets):

- Indicators pointing to the effectiveness of market arrangements in providing locational signals and reflecting the value of electricity, also in times of scarcity, such as the extent to which market prices have been contrained by any implicit or explict limits on prices, levels of investment and correlation with price in different bidding zones.
- State interventions to support resource adequacy and their interaction with the EU's electricity markets, such as their incidence, design features and degree of participation of cross-border capacity;

Problem Area III (reinforce coordination between Member States for preventing and managing crisis situations):

- Indicators for monitoring security of supply, such as expected energy non-served (EENS) and loss of load expectation (LoLE);
- In the case that electricity crisis situations occur, the lessons learnt from these stress situations should also feed in the analysis of security of supply.

Problem Area IV (retail markets):

- The incidence of regulated prices and the progress towards their phase-out;
- Market developments regarding consumer switching, switching facilitation such as switching rates, costs and incidence of price and non-price barriers to switching.
- Key performance indicators measuring the economic and technical effectiveness of DSOs and impact on system users (level of distribution charges).

9. Glossary and Acronyms

ACER	The Agency for the Cooperation of Energy Regulators, a European Union Agency that was created by the Third Energy Package to further progress the completion of the internal energy market both for electricity and natural gas.
ACER Regulation:	Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators, OJ L 211, 14.8.2009, p. 1–14.
Adequacy	(Resource) adequacy can be defined as the ability of the system to meet the aggregate power and energy requirements of all consumers at virtually all times. In this impact assessment the term resource adequacy is favoured over other terms often used in this context, such as generation or system adequacy
aFFR	See FFR
Aggregator	A service provider that combines multiple consumer loads (flexibility or energy) and/or supplied energy units for sale or auction in organised energy markets.
Ancillary Services:	Services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission service provider. They refer to a range of functions which TSOs contract so that they can guarantee system security. These include services like the provision of mFFR and aFFR or reactive power.
Balancing	The situation after markets have closed (gate closure) in which a TSO acts to ensure that demand is equal to supply, in and near real time.
Balancing Guideline	Commission Regulation establishing a Guideline on Electricity Balancing, one of the legal acts to be adopted under Article 18 of the Electricity Regulation.
Balancing reserves	All resources, if procured *ex ante* or in real time, or according to legal obligations, which are available to the TSO for balancing purposes.
BAU	Business As Usual, i.e. the state of the world if no additional action is taken.
Bidding zone	A bidding Zone means a geographical area within which electricity market wholesale prices are uniform and market participants not have to take into account grid constraints. Market participants who wish to buy or sell electricity in another bidding zone have to take into account grid constraints and related congestion rent payments.

BRPs	Balance responsible parties, such as producers and suppliers, keep their individual supply and demand in balance in commerical terms.
BSPs	Balancing Service Providers, such as generators or demand facilities, balance-out unforeseen fluctuations on the electricity grid by rapidly increasing or reducing their power output.
CACM Guideline	Guideline on Capacity Allocation and Congestion Management, one of the legal acts adopted under Article 6 of the Electricity Regulation.
CCGT	Combined Cycle Gas Turbine, a common type of gas-fired generation plant
CEEE	Central Eastern European Electricity Forum, a platform for cooperation between certain EU Member States.
CERT	Computer Emergency Response Team.
CHP	Combined Heat and Power units produce heat and electricity simultaneously. Their production of electricity is not necesarrily deterined only by prices for electricity.
CM	Capacity Mechanism, a regulatory intervention that remunerates the availability of electricity resources instead of the production of electricity (or the avoidance of electricity consumption).
Congestion	Means a situation in which an interconnection linking national transmission networks cannot accommodate all physical flows resulting from international trade requested by market participants, because of a lack of capacity of the interconnectors and / or the national transmission systems concerned.
Conventional generation	The non-low carbon technologies, based on fossil fuels (lignite, hard coal, natural gas, oil). They usually constitute the mid-range and peaking plants.
Cross-zonal transmission capacity:	The capability of the interconnected system to accommodate energy transfers between bidding zones.
CSIRT	Computer Security Incident Response Team.
CT	Comparison Tools, websites that help consumers to compare different offers in the market.
Curtailment	Curtailment means a reduction in the scheduled capacity or energy delivery.
Day-ahead market	The market timeframe where commercial electricity transactions are executed the day prior to the day of delivery of traded products.

DER	Distributed Energy Resources, a generic term referring electricity assets such as small-scale RES E, storage connected to distribution grids or by end-consumers on their premises.
Digital Single Market	EU policy strategy aimed at: (i) helping to make the EU's digital world a seamless and level marketplace to buy and sell; (ii) designing rules which match the pace of technology and support infrastructure development; and (iii) ensuring that Europe's economy, industry and employment take full advantage of what digitalisation offers.
DR	Demand (side) response, the ability of consumers of electricity to actively adapt their consumption to market conditions.
DSO	Distribution System Operator, the entity that operates, maintains and develops the low voltage networks in a given area to which most consumers are connected.
ECG	The Electricity Coordination Group was created in 2012 by Commission Decision of 15 November 2012. The Group is a platform for the exchange of information and coordination of electricity policy measures having a cross-border impact. It also aims to facilitate the exchange of information and cooperation on security of electricity supply, including the coordination of action in case of an emergency within the Union.
EE	Energy Efficiency Directive. Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC. This directive establishes a set of binding measures to help the EU reach its 20% energy efficiency target by 2020.
EEAG	Communication from the Commission - Guidelines on State aid for environmental protection and energy 2014-2020, OJ C 200, 28.6.2014, p. 1–55. The Guidelines aim to help Member States design state aid measures that contribute to reaching their 2020 climate targets. The guidelines will be in force until the end of 2020.
EENS	Expected Energy Non Served, a metric to measure security of supply and to set a reliability standard.
EESC	The European Economic and Social Committee.
Electricity Directive	Directive 2009/72 of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, OJ L 211, 14.8.2009, p. 55–93. Together with the Electricity Regulation, the Electricity Directive sets the main parts of the legal framework for the EU's electricity markets.

Electricity Regulation	Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity repealing Regulation (EC) No 1228/2003, OJ L 211, 14.8.2009, p. 15–35. Together with the Electricity Directive, the Electricity Regulation sets the main parts of the legal framework for the EU's electricity markets.
End-customer	End-customers procure electricity for their own use.
ENTSO-E	European Network of Transmission System Operators for Electricity. ENTSO-E was established and given legal mandates by Third Package.
ENTSO-G	European Network of Transmission System Operators for Gas. ENTSOG was established and given legal mandates by Third Package.
EPBD	Energy Performance of Buildings Directive or Directive 2010/31/EU of the European Parliament and of the Council of 19 May 2010 on the energy performance of buildings. OJ L 153, 18.6.2010, p. 13–35, concerning energy efficiency of building. Modifications are being proposed to the EPBD.
ETS	Emmission Trading System, works on the 'cap and trade' principle. A 'cap', or limit, is set on the total amount of certain greenhouse gases that can be emitted by the factories, power plants and other installations in the system. The cap is reduced over time so that total emissions fall. This policy instrument equally fosters penetration of RES E as it renders production of electricity from non- or less-emitting generation capacity more economical.
EU Target Model:	Term refering to the current design of the EU's electricity markets. The EU target model is based on two broad principles: (i) the development of integrated regional wholesale markets, preferably established on a zonal basis, in which prices provide important signals for generators' operational and investment decisions; and (ii) market coupling based on the so-called "flow-based" capacity calculation, a method that takes into account that electricity can flow via different paths and optimises the representation of available capacities in meshed electricity grids.
EUCO27	The central policy scenario modelled by PRIMES, reflecting the agreed 2030 climate and energy targets (and the 2050 EU's decarbonisation objectives).
FCR	Frequency Containment Reserve are reserves from reserve providers (generators, storage, demand response) used by TSOs to maintain frequency stable in the whole synchronous area (e.g. continental Europe). This category typically includes automatically activated reserves with the activation time up to 30 seconds.

Florence Forum	The Florence Forum was set up to discuss the creation of a true internal electricity market in Europe. The participants are national regulatory authorities, Member States, the European Commission, international organisations in the area of energy and European-wide associations representing transmission and distribution system operators, electricity traders, consumers, network users and power exchanges.
FRR	Frequency Restoration Reserve are reserves from reserve providers (generators, storage, demand response) used by TSOs to restore system frequency and power balance after sudden system imbalance occurrence (e.g. the outage of a power plant). Those reserves replace FCR if the frequency deviation lasts longer than 30 seconds. This category includes operating reserves with an activation time typically between 30 seconds up to 15 minutes. FRR can be distinguished between reserves with automatic activation (aFRR) and reserves with manual activation (mFRR).
Gas Directive:	Directive 2009/73 of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in gas and repealing Directive 2003/55/EC, OJ L 211, 14.8.2009, p. 94–136. Together with the Gas Regulation, the Gas Directive sets the main parts of the legal framework for the EU's gas markets.
Gas Regulation:	Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005, OJ L 211, 14.8.2009, p. 36-54. Together with the Gas Directive, the Gas Regulation sets the main parts of the legal framework for the EU's gas markets.
Gate closure	The moment when contracts are frozen. After gate closure, no trading is allowed anymore. At this point, parties are expected to adhere to the physical data submitted to the System Operator and to the contracted volumes submitted before Gate Closure.
G-charges	Charges for network usage imposed on generators
Generator	A generator produces electricity and sells this to suppliers or end-customers
Independent aggregator	Aggregator that is not affiliated to a supplier or any other market participant.
ITC Regulation	Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging

LFC block	Load-Frequency Control block or balancing zone, defines the size of the network area for which the balancing reserves are being procured.
Load	The total electricity demand
Load Payments	Load Payments correspond to the amount of money retail companies/consumers need to pay to generators for the electricity bought from the wholesale market. For each hour, it corresponds to the product of served demand with the electricity price.
LoLE	Loss of load expectation, a metric to measure security of supply and to set a reliability standard
LTC	Long-term contract.
METIS	A modelling tool used by the Commission, described in more detail in Annex IV.
mFFR	See FFR
NC ER	Network Code on Emergency and Restoration
NEMO	Nominated Electricity Market Operator; an entity designated by competent authroities to perform tasks related to single day-ahead and intraday coupling as defined in the Guideline on Capacity Allocation and Congestion Management, one of the legal acts adopted under Article 6 of the Electricity Regulation.
Electricity network codes	and guidelines: a legal act adopted under Articles 6, 8 and 18 of the Electricity Regulation. Examples of such codes and guidelines are the NC ER, the CACM guideline, the RfG, the System Operation Guideline or the Balancing guideline. For a full overview of these network codes and guidelines, reference is made to Annex VII.
NIS Directive	Directive (EU) 2016/1148 of the European Parliament and of the Council of 6 July 2016 concerning measures for a high common level of security of network and information systems across the Union, OJ L 194, 19.07.2016, p. 1-30.
NRAs	National Regulatory Authorities, are national authorties set up and empowered by the Third Package to over see national electricity (and gas) markets.
NTC	Net Transfer Capacity, a metric to measure the capacity available on interconnectors to transfer electricity.
Plan	Risk Preparedness Plans, a measure proposed under Problem Area III
PLEF	Pentalateral Energy Forum, a platform for collaboration consisting of the Ministries, NRAs and TSOs of the BENELUX, DE, FR, AT,

	CH as well as a market parties platform and the European Commission.
Power exchange	Power exchanges facilitate the trading of electricity at wholesale level, often for delivery the next day or at even shorter intervals (intraday). They cooperate with TSOs in optimising interconnection capacity in the contex of market coupling.
PRIMES	A modelling tool used by the Commission, described in more detail in Annex IV.
PV	Photovoltaic
RED II	The Renewable Energy Package comprising the new Renewable Energy Directive and bioenergy sustainability policy for 2030
Redispatching	A measure activated by one or several system operators by altering the generation and/or load pattern in order to change physical flows in the transmission system and relieve a physical network congestion.
Regional platform	A platform or regionally coordinated platforms for the attribution of Long Term Cross Zonal Capacity for a single border or set of borders.
RES E	Renewable sources of electricity
RfG	Network code on Requirements for Grid Connection of Generators
ROC	Regional Operational Centre
RR	Replacement Reserve are reserves from reserve providers (generators, storage, demand response) used by TSOs to restore the required level of FCR and FRR due to their earlier usage. Contrary to FCR and FRR, not all TSOs in the EU maintain RR. This category includes operating reserves with activation time from several minutes up to hours.
RSC	Regional Security Coordinators, an entity foreseen under the System Operation Guidelines to assist TSOs in maintaining the operational security of the electricity system.
Sector Inquiry	The sector inquiry into capacity mechanisms as conducted by DG Competition of the European Commission
Smart meter	An electronic device that records consumption of electric energy in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing. Smart meters enable two-way communication between the meter and the central system.

SME	Small and Medium-sized Enterprises as defined in the Commission Recommendation of 6 May 2003 concerning the definition of micro, small and medium-sized enterprises (notified under document number C(2003) 1422), OJ L 124, 20.05.2003, p. 36-41.
SoS Directive	Security of Electricity Supply Directive or Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment, OJ L 33, 4.2.2006, p. 22–27
Supplier	Suppliers are active in the retail segment of the market and supply electricity to end-consumers
Switching rate	The percentage of consumers changing suppliers in any given year.
System Operation Guideline:	Draft Commission Regulation which will set down rules relating to the maintenance of the secure operation of the interconnected transmission system in real time.
TFEU	Treaty of the Functioning of the European Union
Third Package:	A package of legislation adopted in 2009 comprising the Electricity Directive, the Electricity Regulation, the ACER Regulation as well as similar legislation concerning the gas markets.
ToU tariffs	Time-of-Use tariffs: Time-based pricing is a pricing strategy where the provider of a service or supplier of a commodity, may vary the price depending on the time-of-day when the service is provided or the commodity is delivered.
Transmission capacity	The transmission capacity, also called TTC (Total Transfer Capacity), is the maximum transmission of active power in accordance with the system security criteria which is permitted in transmission cross-sections between the subsystems/areas or individual installations.
TRM	Transmission Reliability Margin, a metric to capture the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission system will be secure during changing system conditions
TSO	Transmission System Operator, the entity that operates, maintains and develops the high voltage networks in a given area.
TYNDP	Ten-Year Network Development Plan
VCWG	The Vulnerable Consumer Working Group provides advice to the European Commission on the topics of consumer vulnerability and energy poverty, its membership comprising industry, consumer associations, regulators and Member States representatives.

VoLL	Value of Lost Load is a projected value reflecting the maximum price consumers are willing to pay to be supplied with electricity. VoLL is typically quite high (e.g. several thousands of EUR/MWh) and not necessarily the same for each (group of) consumer, thus enabling DR activation by consumers before the VoLL is reached.

EUROPEAN
COMMISSION

Brussels, 30.11.2016
SWD(2016) 410 final

PART 2/5

COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT

Accompanying the document

Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast)

Proposal for a Regulation of the European Parliament and of the Council on the electricity market (recast)

Proposal for a Regulation of the European Parliament and of the Council establishing a European Union Agency for the Cooperation of Energy Regulators (recast)

Proposal for a Regulation of the European Parliament and of the Council on risk preparedness in the electricity sector

{COM(2016) 861 final}
{SWD(2016) 411 final}
{SWD(2016) 412 final}
{SWD(2016) 413 final}

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ANNEXES

Annex I: Procedural information

Lead DG: DG Energy

Agenda planning/Work Programme references:

- AP 2016/ENER/007 (Initiative to improve the electricity market design)
- AP 2016/ENER/026 (Initiative to improve the security of electricity supply)

Publication of Inception Impact Assessment:

- October 2015 (Initiative to improve the electricity market design)
- October 2015 (Initiative to improve the security of electricity supply)

No feedback was received on the Inception Impact Assessments

Inter-service group:

An Inter-service group meeting was used comprising the Legal Service, the Secretariat-general, DG Budget, DG Agriculture and Rural development, DG Climate action, DG Communications Networks, Content and Technology, DG Competition, DG Economic and Financial Affairs, DG Employment, Social affairs and Inclusion, DG Energy, DG Environment, DG Financial stability, Financial services and Capital markets, DG Internal market, Industry, Entrepreneurship and SMEs, the Joint Research Centre, DG Justice and Consumers, DG Mobility and Transport, DG Regional and urban development, DG Research and innovation, DG Taxation and Customs Union.

Not all Directorate-generals did participate in each ISG meeting

Meetings of this ISG were held on: 28 October 2015, 25 April 2016, 20 June 2016 and 8 July 2016

Consultation of the RSB

The impact assessment was submitted to the RSB on 20 July 2016. On 14 September 2016, the impact assessment was discussed with the RSB. On 16 of September 2016 the RSB issued it opinion, which was negative. It requested to receive a revised draft of the IA report addressing its recommendations whilst briefly explaining what changes have been made compared to the earlier draft. A draft impact assessment was resubmitted on 17 October 2016. A positive RSB Opinion, with reservations, was issued on 7 November 2016?

The opinions and the changes made in response are summarised in the tables below.

Comments made by RSB in first Opinion of 16 September 2016	Modifications made in reaction to comments RSB
Issues cross cutting to other impact assessments	
This IA and the IA on the revision of the renewables directive need a coherent analysis of renewable electricity support schemes. They need to reconcile different expectations of what the market will deliver in terms of the share of renewable electricity and of the participation of prosumers. Given uncertainty on these issues, both IAs should incorporate the same range of possible outcomes in their analysis	An explicit vision of the EU electricity market has been incorporated in section 1.1.1.4. This vision includes a section on the connection with the share of RES E and prosumers.
The IA should clarify and explain the content and assumptions of the baseline scenario in relation to the other parallel initiatives	A dedicated section was included in Annex IV clarifying all points raised concerning the baseline, REF2016 and EUCO27. The baseline description in 5.1.2, 5.2.2, 6.1.1.2 and 6.1.1.4 was improved and references were made to its more detailed description in the Annex.
Issues specific to the present impact assessment	
The IA report is too long and complex to make it helpful in informing political decisions. The Board recommends that this report begin with a concise, plain-language abstract of approximately 10-15 pages. This abstract should summarise the key elements of the IA and identify the main policy trade-offs	A plain-language abstract has been added at the beginning of the document.
The report should present a clear vision for the EU electricity market in 2030 and beyond with a distinction between immediate challenges and longer term developments. This vision needs to be coherent with EU policies on competition, climate and energy. It also needs to be consistent with the parallel initiatives, notably the revision of the RES Directive. In particular, this applies to the assumptions and expectations on what the new electricity market design could deliver on its own and whether the renewable target requires complementary market intervention.	An explicit vision of the EU electricity market has been incorporated in section 1.1.1.4 covering issues mentioned. A detailed section on in RES E in connected with the MDI is contained in a text box in section 6.2.6.3. Another box is located in Section 2.1.3. Further clarifications have been added in section 1.2.1 on interlinkages with RED II.
Based on a common (with other parallel initiatives) baseline scenario, the report should prioritise the issues to be addressed, present an appropriate sequencing and strengthen the treatment of subsidiarity considerations such as for action related to energy poverty and distribution system operators.	A dedicated section was introduced in Annex IV clarifying all points raised concerning the baseline, REF2016 and EUCO27. The baseline description in 5.1.2, 5.2.2, 6.1.1.2 and 6.1.1.4 was improved and references were made to its more detailed description in the Annex.

Comments made by RSB in first Opinion of 16 September 2016	Modifications made in reaction to comments RSB
	A dedicated section on sequencing was introduced as section 7.5.3 Regarding the treatment of subsidiarity for actions related to energy poverty, please see sections 5.4.4; and 5.4.5. The report assesses the options with regards to subsidiarity. It argues that measures in Option 1 are proportionate and in line with the subsidiarity principle while measures in Option 2 entail significant costs and may be better carried out by national authorities.
When assessing the impacts of the different options, the report should indicate whether and how the models of "energy only markets" will coexist with capacity mechanisms and assess the risks of an uncoordinated introduction of capacity remuneration mechanisms across the EU. The impact analysis should also report on the effectiveness of the options to deliver the adequate investment and price responses.	On how the models of "energy only markets" will coexist with CMs, clarifications have been introduced in section 2.2.2. Section 6.2.6 now includes a sub-section on investments, discussing all relevant issues.
Main recommendations for improvements	
The analysis of support schemes for renewable electricity should be consistent across this impact assessment and the one covering renewable energy sources. The reports should clarify what support schemes will be needed, and whether these are needed only in case the market fails to deliver the 2030 EU target of at least 27% of RES in final energy consumption, or will be used to promote certain types of renewable energy.	An explicit vision of the EU electricity market has been incorporated in section 1.1.1.4. This includes a vision on whether outside-the- market measures to support for RES E are needed up to 2030. The question what type of out-of-market support mechanisms are needed falls within the remit of the RED II IA. A dedicated section was included in Annex IV clarifying all points raised concerning the baseline. Via the definition of the baseline, the impact assessment for the MDI and RED II are fully compatible, including as regards the assessment of support schemes.
The IA should take into account the tendering procedure envisaged for procuring support for renewable energy producers and assess its impact on the electricity market.	An explicit vision of the EU electricity market has been incorporated in section 1.1.1.4. This includes a vision on whether outside-the- market measures to support for RES E are needed. A detailed section on in RES E in connected with the MDI is contained in a text box in section 6.2.6.3. Further clarifications have been added in section 1.2.1 on interlinkages with RED II.

Comments made by RSB in first Opinion of 16 September 2016	Modifications made in reaction to comments RSB
In addition, even though the report does not present a blueprint for a capacity remuneration mechanism (as it is in the remit of the state-aid guidelines/EU competition policy), it should analyse possible detrimental effects of such mechanisms being introduced in the EU in an uncoordinated fashion. In particular, the IA should examine distortions to investment incentives and price setting mechanisms.	The clarification in Annex IV as regards the baseline explains how, the impact assessments for the MDI and RES E are fully compatible, including as regards to the tendering procedure (see section on current market arrangements in Annex IV). Text adapted in section 2.2.2 and included a reference to forthcoming report by DG Competition.
The expected involvement of consumers and prosumers in supplying electricity and managing its demand has to be consistent across the two impact assessments. The analysis should integrate the effects of potentially more volatile electricity prices and high fixed network costs on prosumer involvement and on the long-term risk that these might disconnect from the network as local storage technology evolves.	An explicit vision of the EU electricity market has been incorporated in section 1.1.1.4. This includes a vision on prosumers and the risk of disconnection, which is further developed in a text box in Section 6.1.4.2. Also the RED II IA has been adjusted.
In devising the options, the report should be proportionate to the importance of the problems/objectives and realistic in assessing what can be achieved. For instance, options linked to the issue of energy poverty (being part of the social policy) should be built around increasing transparency and peer pressure among Member States rather than the single market motive.	See section 2.4.1 and section 5.4.4. The report clarifies the main objective of the measures linked to energy poverty (i.e. description of the term 'energy poverty' and measurement of energy poverty), which already apply to Member States (Member States should address energy poverty where it is identified). Better monitoring of energy poverty across the EU will, on one hand, help Member States to be more alert about the number of households falling into energy poverty, and on the other hand, peer pressure encourages Member States to put in place measures to reduce energy poverty.
The baseline scenario should be clarified, including the link with the 2016 reference scenario and underlying assumptions	A dedicated section was included in Annex IV clarifying all points raised concerning the baseline, REF2016 and EUCO27.
Some more technical comments have been transmitted directly to the author DG and are expected to be incorporated into the final version of the impact assessment report	All technical comments have been addressed.

Comments made by RSB in first Opinion of 16 September 2016	Modifications made in reaction to comments RSB
The IA report needs to be more reader-friendly and helpful for decision-making. The report should contain a 10-15 page abstract that succinctly presents the main elements of the analysis, the policy trade-offs and the conclusions. The main text should be streamlined to contain the crucial elements of the analysis in the main part of the report	A reader friendly abstract that succinctly presents the main elements of the analysis, the policy trade-offs and the conclusions has been added to the main text of the IA.

Comments made by RSB in second Opinion on 7 November 2016	Modifications made in reaction to comments RSB
Opinion RSB on resubmission	
Restoring price signals for investments is one crucial element of the revised market design. The report is clearer on its view that undistorted markets deliver the right price signals for investment. The report should more convincingly explain how adequate pricing could be achieved in the presence of national capacity markets and subsidies for renewables which might exacerbate excess capacity in the market. The report should assess the risk of persistent low electricity wholesale prices and associated consequences for the effectiveness of the initiative. What would be the effects for investment, demand response, elimination of subsidies, and consumer benefits?	Reference is made to the new Box 9 underneath Section 6.4.6 for further explanations, which was added following the RSB comments.
Further recommendations for improvements	
Internal coherence and risks: The analysis in the report demonstrates that the vision for the EU electricity market in 2030 and beyond relies on the implementation of many different policies and assumptions, and is subject to numerous risks. The narrative of the report should more clearly reflect these risks. The report should propose modalities to review assumptions and monitor implementation at intermediate stages. The text of the report should reflect the trade-off between restoring the EU internal energy market in its pure form and government intervention to support renewable energy sources and to maintain security of supply.	Text has been added to Sections 8.1 and 8.2.2 with regard to the reviewing of assumptions and monitoring of implementation. The 2030 RES E objectives are part of the base-line of the analyses. Trade-offs between government interventions in support of RES E are investigated in the REDII impact assessment. However, in the present report, it has been rendered more clearly what elements of the RED II initiative are important to the impacts of the present initiative. See in this regard Section 1.1.1, 1.2.1, Box 7 under section 6.2.6.3, Box 9 under Section 6.4.6 and Annex IV. It is noted that improving market functioning reduces the need for government intervention with regard to both RES E (See Section 1.1.1.4, Box 7 below section 6.2.6.3 and section 7.5.1) and resource adequacy (See section 6.2.2.1, Section 6.2.6.3 and Section 7.5.1).
Impact analysis: The vision of an energy Union places citizens at its core. The report should therefore better address the risks and benefits to consumers, especially with regard to expected higher price variability. It should discuss not just possible long run benefits, but also costs (including switching	The risks of greater price variability have been introduced in two new text boxes in Section 5.1.4.3 (Box 4) of the main impact assessment document, and in Section 3.1.5 of the Annexes to the Impact Assessment. These specifically address the benefits and risks of dynamic electricity pricing

Comments made by RSB in second Opinion on 7 November 2016	Modifications made in reaction to comments RSB
fees) in the short and medium term. In the same vein, the report should examine the impact of the policy on various groups of consumers	contracts, which are a frequent concern of consumer groups. The impacts of the measures in Problem Area IV (Retail Markets) on different groups of consumers have been addressed in a text box in Section 6.4.3.2 of the Impact Assessment Report (Box 8) and text boxes in Sections 7.1.5, 7.2.5, 7.3.5, 7.4.6, 7.5.5, and 7.6.6 of the Annexes to the Impact Assessment.
While the Board takes note that impacts are based on modelling, the results of the modelling should be critically reviewed to avoid false expectations, in view of many assumptions taken. For instance, the modelling results in the average level of wholesale prices at 74€/MWh already in 2020 and 103€/MWh in 2030). The attainment of these price levels is hard to imagine in reality, given that currently that level is around 34€ and more renewable capacity is being deployed into the system, still benefitting from the current support schemes for RES-E (based mostly on feed-in tariffs). Lower than modelled wholesale prices could seriously undermine the investment outcome, the assumed increased engagement of consumers and demand response – the cornerstones of the EU Energy Union.	To improve clarity, the new Box 9 includes further explanations. Please also see new footnotes 345 and 384 .
Similarly, the effectiveness of the revised RES-E support schemes (as proposed in the RED II IA) is not critically discussed. First, the report needs to emphasize that they would not be based on any type of feed-in tariff but premiums on top of market revenues and these premium will be auctioned. Second, the report needs to consider the fact that such auctions may not necessarily be effective in reducing the support to renewable energy sources. This is particularly relevant in a situation where the share of renewables in the electricity generation mix is expected to grow	It has been made clearer that market based support schemes, such as premium schemes combined with auctions, are an underlying premise of the impacts of the present initiative. (See section 1.1.1, 1.2.1, Box 7 under section 6.2.6.3, Box 9 underneath section 6.4.6 and Annex IV) The phase-out of non-market based support schemes has already commenced under the EEAG adopted in 2014 and is further reinforced by the measures proposed by RED II. It is therefore assumed that non-market based support schemes are fully

Comments made by RSB in second Opinion on 7 November 2016	Modifications made in reaction to comments RSB
substantially and the wholesale prices will be depressed at least until the current support schemes for RES-E are reviewed in 2024.	phased out by 2024, whereas the impact assessment looks at the situation in 2030. For more detail see Annex IV. The cost effectiveness of the RES E support schemes as such is the subject of the RED II impact assessment.
Procedure and presentation	
While the report is still very long, the inclusion of the abstract has improved the presentation of relevant information, though the issue of policy trade-offs (market vs. government interventions) should be emphasized more explicitly	References to policy trade-offs (market versus government intervention) have been further emphasised. See for instance the abstract, page 10 and 13 and Sections 6.2.2.1, 6.2.6.3 and 7.5.1. Furthermore, Options 2 and 3 under problem area II expressly seek to address the compatibility of government intervention in a market context.

An overview of evidence and external expertise used is provided in a separate annex.

Annex II: Stakeholder consultations

Public consultations

In preparation of the present initiative, the Commission has conducted several public consultations, in particular:

- public consultation on generation adequacy, capacity mechanisms, and the internal market in electricity, conducted in 2013;
- consultation on the retail energy market, conducted in 2014;
- public consultation on a new energy market design, conducted in 2015;
- public consultation on risk preparedness in the area of security of electricity supply, conducted in 2015.

These public consultation and their results are describe in more detail below.

Stakeholder opinions are also summarised in boxes for each main policy option in section 5 and, if appropariate, elsewhere of the present impact assessment. Even more detailed representations of stakeholder opinions are contained in Section 7 of each the annexes assessing the options for detailed measures.

Public consultation on generation adequacy, capacity mechanisms, and the internal market in electricity

Resource adequacy related issues were the subject of a public consultation[1] conducted from 15 November 2012 to 7 February 2013 through the *"Consultation on generation adequacy, capacity mechanisms, and the internal market in electricity"*. It was open to EU and Member States' authorities, energy market participants and their associations, and any other relevant stakeholders, including SMEs and energy consumers, and citizens. It aimed at obtaining stakeholder's views on ensuring resource adequacy and security of electricity supply in the internal market.

As regards the quality and representativeness of the consultation, the consultation received 148 individual responses from public bodies, industry (both energy producing and consuming) and academia. Most responses (72%) came from industry. Responses were of a high standard, not only engaging with the questions posed and the challenges being addressed, but bringing valuable insights to the Commission's reflections of this important topic. The consultation appears representative in comparison with similar consultations.

1 https://ec.europa.eu/energy/sites/ener/files/documents/20130207_generation_adequacy_consultation_document.pdf

The following paragraphs provide a summary of the responses available on the Commission's website[2]. The responses and a summary thereof are also available on the Commission's website[3].

(i) *Government interventions.* Respondents to the consultation responses repeatedly highlighted the policy uncertainty and national uncoordinated interventions of various kinds, in particular support for renewables, as being critical elements in discouraging investment. This was highlighted frequently by industry and also by academics and think tanks. The related issue of fixing the flaws of ETS was also raised repeatedly by industry. For example Energy UK states that *"national measures often response to a lack of coherence in EU energy policy itself – in particular there is a conflict between the market driven approach to liberalisation and to EU ETS and the various sectoral targets in renewables, energy efficiency etc."* The Netherlands (Ministry of Economic Affairs) *responded "the absence of a credible carbon policy and a lack of proper market functioning cannot be underestimated"*;

(ii) *Market functioning***.** In the context of a weak demand and economic crisis, Europe's energy markets today area was deemed characterised by two developments: the integration of large amounts of renewables and the implementation of the EU target model. This was clearly reflected in the responses to this consultation. Overall respondents' opinions were split as to whether energy-only markets could deliver investments needed to ensure generation adequacy and security of supply. However, there is near unanimous support from respondents for the importance of the completion of the integration of day-ahead, and close to real time markets as a an important contributor to security of supply although, some respondents caution that this will not address fundamental problems with whether energy-only markets can deliver resource adequacy Similarly, there are strong calls facilitating demand side response and the development of grids in line with the ten year network development plan. Almost all responses to the consultation raised the impact of RES E on the market. For example the UK response discusses the impact that more low marginal cost pricing will have on the market, and the issue is discussed in detail in the Clingendael paper submitted in response to the consultation. Industry in particular raised the issue about the impact that RES E support schemes had on the market. While many raise the issue of any out-of-market support creating distortions, the position set out in the response of Eneco, a Dutch company is worth quoting *"In general, support for specific energy sources does not undermine investments to ensure generation adequacy, it just changes the merit order. But details of support mechanisms can, specifically if a support mechanism lowers the value of flexibility"*. This consideration can be seen in the numbers of

[2] https://ec.europa.eu/energy/sites/ener/files/documents/Charts_Public%20Consultation%20Retail%20Energy%20Market.pdf

[3] https://ec.europa.eu/energy/en/consultations/consultation-generation-adequacy-capacity-mechanisms-and-internal-market-electricity

respondents who cite priority dispatch or lack of balancing responsibility for RES E producers as posing particular problems on the market, an issue which is separate from the level of support for RES producers, as indeed recognised by Germany who stat in their response *"Allerdigs ist ein Umstieg von der Festvergutuetung unter der garantierten Abnahme des EE-Stroms auf ein System der Marktintergration notwendig, in dem die Erneueuerbaren ihre Einspeisung an dem Marktpreissignal orientieren…"*.

(iii) *Assessing security of supply.* There is widespread recognition of a need for improved assessment of generation and security of supply in the internal market given the impact of both RES E and market integration. Proposal have been made suggesting a need for more scenario analysis based on different weather conditions, different timespans for the assessment (long-term, short-term), more detailed assessment of flexibility and more coordination between TSOs and more sensitivity analysis. In this regard the existing ENTSO-E generation adequacy assessment is not felt to meet future needs, without suggesting that ENTSO-E is not carrying out its current role properly. There is particularly strong support for more regional generation adequacy assessments combined with a common methodology for undertaking such assessments. For example France in its response states *"Il pourrait notamment être utile de renforcer la cohérence à l'échelle régionale des différentes méthodes d'analyse et des scénarios produits au niveau national, souvent interdépendants. Ces analyses régionales viendraient ensuite alimenter un exercice réalisé à l'échelle de l'Union"*. Support for binding standards is less strong among respondents. Many of those who, in principle, would welcome common standards point to the difficulties in establishing such standards while MS retain responsibility for Security of Supply (and hence determining standards). Others (such as the Oeko institute) consider that more harmonised activities of Member states are essential in the internal market. There was limited support for a revision of the Security of Supply directive, which was perceived to fulfil its limited role. Again France states that *"Il apparaît préférable de privilégier l'élaboration rapide de ces codes et achever ainsi la mise en oeuvre des dispositions du 3ème paquet avant d'envisager des mesures nouvelles au travers de la refonte de cette directive."* However some stated that since the Directive was adopted before the Third Package, the situation after the Third Package is different and therefore the level of cooperation prescribed by the Directive does not correspond to today's situation. Summarising, there was widespread support for a reassessment of how generation adequacy and security of supply are assessed, and a recognition for the need for actions to be coordinated. The question which stands out is what are the best tools to do this. Here the electricity coordination group ('ECG') (explicitly mentioned by several respondents) can play a critical role. The Commission will continue to examine what are the best tools available to achieve the widely supported aim of improved generation adequacy assessment.

(iv) *Interventions to ensure security of supply.* As already noted opinion is divided on whether energy only markets can deliver the investments which will be needed to ensure generation adequacy and security of supply in the future. However, there were even more varied opinions on the effectiveness of different capacity remuneration mechanisms. Given this divergence of opinion therefore there is only limited support for a European blueprint, many respondents pointing to divergent local circumstances and the need to address specific problems as

militating against such an approach. Against this there was very strong support, particularly among industry and academica, for EU wide criteria, governing capacity mechanisms extending also to the high level criteria which proposed in the consultation paper. Among Member States the UK specifically called for criteria to be linked to State aid assessments, and notwithstanding caution about overly detailed assessment at EU level its detailed comments on the individual criteria in the consultation paper were broadly supportive. FR states *"Il est toutefois utile et légitime que la Commission européenne suive de près l'impact des choix des Etats membres sur le marché intérieur"* but also cautions that *"Il semble prématuré à ce stade de définir des critères détaillés de compatibilité avec le marché intérieur"*. DE states that the Commission *"im Bedarfsfall eintreten, der die Koordinierung zwischen den MS zu einer stärker gemeinsamen …Gewährleistung der Versorgungssicherheit erleichtert*.".

Consultation on the retail energy market

A public consultation dedicated to electricity retail markets and end-consumers[4] was conducted from 22 January 2014 to 17 April 2014. It was open to all EU citizens and organizations including public authorities, as well as relevant actors from outside the EU. This public consultation aimed at obtaining stakeholder's views on the functioning of retail energy markets.

As regards representativeness and quality, the Commission received 237 responses to the consultation. About 20% of submissions came from energy suppliers, 14% from DSOs, 7% from consumer organisations, and 4% from NRAs. A significant number of individual citizens also participated in the consultation.

The following paragraphs provide a summary of the responses, which are also available on the Commission's website[5].

(v) *Retail competition.* Respondents to this public consultation felt that market-based customer prices are an important factor in helping residential customers and SMEs better control their energy consumption and costs (129 out of 237 respondents considered that it was a very important factor while other 66 qualified it as important for the achievement of the said objective). Moreover, out of 121 respondents who considered that the level of competition in retail energy markets is too little, 45 recognised regulation of customer prices as one of the underlying drivers.

81% of the respondents agreed that allowing other parties to have access to consumption data in an appropriate and secure manner, subject to the consumer's explicit agreement, is a key enabler for the development of new energy services for consumers.

4 https://ec.europa.eu/energy/en/consultations/consultation-retail-energy-market

5 https://ec.europa.eu/energy/sites/ener/files/documents/Charts_Public%20Consultation%20Retail%20Energy%20Market.pdf

As regards whether it is sufficiently easy without facing disproportionate permitting and grid connection procedures for a consumer to install and connect renewable energy generation and micro-CHP pursuant to the provisions of the RES and Energy performance in buildings Directives the views are split.

(vi) *Consumer issues.* 222 out of 237 respondents to the retail market public consultation believed that transparent contracts and bills were either important or very important for helping residential consumers and SMEs to better control their energy consumption and costs.

When asked to identify key factors influencing switching rates, 89 respondents out of 237 stated that consumers were not aware of their switching rights, 110 stated that prices and tariffs were too difficult to compare due to a lack of tools and/or due to contractual conditions, and 128 cited insufficient benefits from switching.

178 out of 237 agreed that ensuring the availability of web-based price comparison tools would increase consumers' interest in comparing offers and switching to a different energy supplier. 40 were neutral and 4 disagreed.

Only 32 out of 237 respondents agreed with the statement: "There is no need to encourage switching". 98 disagreed and 90 were neutral.

(vii) *DSOs and network tariffs.* The majority of the respondents consider that DSOs should carry out tasks such as data management, balancing of the local grid, including distributed generation and demand response, and connection of new generation/capacity (e.g. solar panels). The majority of stakeholders thought these activities should be carried out under good regulatory oversight, with sufficient independence from supply activities, while a clear definition of the role of DSOs (and TSOs), but also of the relationship with suppliers and consumers, is required.

Regarding distribution network tariffs, 34% of the respondents consider that European wide principles for setting distribution network tariffs are needed, while another 34% is neutral and 26% disagree. Time-differentiated tariffs are supported by ca 61% of the respondents, while the majority of stakeholders consider that cost breakdown (78%) and methodology (84%) of distribution network tariffs should be transparent.

The majority of stakeholders also consider that self-generators/auto-consumers should contribute to the network costs even if they use the network in a limited way. To this end, ca. 50% of the respondents consider that the further deployment of self-generation with auto-consumption requires a common approach as far as the contribution to network costs is concerned.

Regarding self- consumption, self- consumers should contribute to network costs even if they use the network in a limited way and further deployment would require a common approach. Moreover, however the responders think that to this end a common approach with simplified related administrative procedures is required. Granting of financial incentives by Member States to promote self-generation and auto-consumption splits views evenly.

(viii) *Demand response.* Over 50% of the responders think that residential consumers lack sufficient information to use energy efficiently and make use of advances in innovation that have enabled a broad range of distributed generation and demand response for industrial and commercial consumers. While the views are split in respect to the ESCOs role to facilitate the favourable contractual arrangements and other related services and as regards the access to respective choices of energy efficiency services consumers have. Similarly, responders' views diverge when assessing whether there should be done more to support the establishment of ESCOs that are active in the field of energy efficiency. In particular, 44% of the answers indicate that indeed there is more room to support ESCOs establishment and 28% of the answers received point out that are satisfied with the related service.

Moving on, the overwhelming majority industrial consumers are satisfied by their access to demand response and balancing services while on the same question the views coming from SMEs and commercial suppliers are split. Further, 24 of the residential consumers have access to demand response and balancing services while this percentage is 35% for the commercial sector and SMES and reached the 66% for industrial customers. As to the entity of the demand response service provider, over than 70% of the responders believe that this service should be provided by the suppliers, though 50% thinks that aggregators are also fit to provide the service while a minority would allocate this task to the DSOs.

Most responders view that they should be able to be participating in aggregation programmes irrespective of their load size in primary balance markets. The best way of making this happen is through aggregators and developing products taken into account consumers flexibility characteristics and size. In addition, responders' tend to agree that related demand response products should be hassle-free, applicable to all consumers' profiles. People also disagree with the claim that very specific data management tasks with regards to various distribution network actors should be defined at European level.

Suppliers are perceived as having the most access to dynamic pricing and/or time differentiated tariffs. They should first and aggregators, as a second choice, offer demand response services and dynamic pricing to residential consumers, SMEs. Unclear benefits, regulatory barriers and then unclear legal framework are identified as the greatest barriers to limited dynamic pricing in a country. Some respondents indicated that strengthening of infrastructure will allow greater retail market competition

Responses agree that consumers should have a right to a smart meter installed at their own request and at their expense also in regions without general rollout. However, there is a slight tendency against having the choice of a smart meter with functionalities of their own choice even if a different type is rolled out in their area. In respect to smart appliances and energy management systems, responders consider them as important to make the field of demand response accessible to a broad range of consumers and that they can work as facilitators to this end. The views also favour the display of consumption and consumption patterns by the smart appliances and do not consider this as a detriment to the consumers' comfort.

Public consultation on a new energy market design

A wide public consultation[6] on a new energy market design (COM(2015)340 was conducted from 15 July 2015 to 9 October 2015. It was open to EU and Member States' authorities, energy market participants and their associations, SMEs, energy consumers, NGOs, other relevant stakeholders and citizens. This public consultation aimed at obtaining stakeholder's views on the issues that may need to be addressed in a redesign of the European electricity market.

As regards representativeness and quality, the Commission received 320 replies to the consultation. About 50 % of submissions come from national or EU-wide industry associations. 26% of answers stem from undertakings active in the energy sector (suppliers, intermediaries, customers), 9% from network operators. 17 national governments and several national regulatory authorities submitted also a reply. A significant number of individual citizens and academic institutes participated in the consultation.

The first assessment of the submissions confirmed broad support of a number of key ideas of the planned market design initiative, while views on other issues vary. The following paragraphs provide a summary of the responses, also available on the Commission's website[7].

(i) *Electricity market adaptations*. A large majority of stakeholders agreed that scarcity pricing, i.e. price formation better reflecting actual demand and supply, is an important element in the future market design. It is perceived, along with current development of hedging products, as a way to enhance competitiveness. While single answers point at risks of more volatile pricing and price peaks (e.g. political acceptance, abuse of market power), others stress that those respective risks can be avoided (e.g. by hedging against volatility). Regulated prices are perceived as one of the most important obstacles to efficient scarcity pricing.

A large number of stakeholders agreed that scarcity pricing should not only relate to time, but also to locational differences in scarcity (e.g. by meaningful price zones or locational transmission pricing). While some stakeholders criticised the current price zone practice for not reflecting actual scarcity and congestions within bidding zones, leading to missing investment signals for generation, new grid connections and to limitations of cross-border flows, others recalled the complexity of prices zone changes and argued that large price zones would increase liquidity.

Many submissions highlight the link between scarcity pricing and incentives for investments/capacity remuneration mechanisms, as well as the crucial role of scarcity pricing for kick-starting demand response at industrial and household level.

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6 https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

7 https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

Most stakeholders agree with the need to speed up the development of integrated short-term (balancing and intraday) markets. A significant number of stakeholders argue that there is a need for legal measures, in addition to the technical network codes under development, to speed up the development of cross-border balancing markets, and provide for clear legal principles on non-discriminatory participation in these markets.

Most stakeholders support the full integration of Renewable energy sources (RES) into the market, e.g. through full balancing obligations for renewables, phasing-out priority dispatch and removing subsidies during negative price periods. Many stakeholders note that the regulatory framework should enable RES to participate in the market, e.g. by adapting gate closure times and aligning product specifications. A number of respondents also underline the need to support the development of aggregators by removing obstacles for their activity to allow full market participation of renewables.

As concerns phasing out of public support schemes for RES, stakeholders take different positions. While some argue for phasing out support schemes as soon as possible, others argue that they will remain an important tool until technologies have fully matured. They point at existing fossil fuel subsidies and the need to continue subsidizing RES and maintaining other market corrections as long as subsidies for traditional fuels and nuclear are not removed. Certain stakeholders underline that support could progressively take more and more the form of investment aid (as opposed to operating aid). A large majority of stakeholders is in favour of some form of coordination of regional support schemes. The need for an ETS reform to allow full market integration of RES was mentioned very often. Most stakeholders agree that diversified charges and levies are a source of market distortions.

(ii) *Resource adequacy*. A majority of answering stakeholders is in favour an "energy-only" market, possibly augmented with a strategic reserve. Many generators and some governments disagree and are in favour of capacity remuneration mechanisms. Many stakeholders share the view that properly designed energy markets would make capacity mechanisms redundant.

There is almost a consensus amongst stakeholders on the need for a more aligned method for resource adequacy assessment. A majority of answering stakeholders supports the idea that any legitimate claim to introduce capacity remuneration mechanisms should be based on a common methodology. When it comes to the geographical scope of the harmonized assessment, a vast majority stakeholders call for regional or EU-wide adequacy assessment, while only a minority favour a national approach. There is also support for the idea to align adequacy standards across Member States. Stakeholders clearly support a common EU framework for cross-border participation in capacity mechanisms.

(iii) *Retail issues*. Many stakeholders identified a lack of dynamic pricing (more flexible consumer prices, reflecting the actual supply and demand of electricity) as one of the main obstacles to kick-starting demand side response, along with the distortion of retail prices by taxes/levies and price regulation. Other factors include market rules that discriminate consumers or aggregators who want to offer demand response, network tariff structures that are not adapted to demand response and the slow roll-out of smart metering. Some stakeholders underline

that demand response should be purely market driven, where the potential is greater for industrial customers than for residential customers. Many replies point at specific regulatory barriers to demand response, primarily with regards to the lack of a standardised and harmonised framework for demand response (e.g. operation and settlement).

Regarding the role of DSOs, the respondents consider active system operation, neutral market facilitation and data hub management as possible functions for DSOs. Some stakeholders point at a potential conflict of interests for DSOs in their new role in case they are also active in the supply business and emphasized that the neutrality of DSOs should be ensured. A large number of the stakeholders stressed the importance of data protection and privacy, and consumer's ownership of data. Furthermore, a high number of respondents stressed the need of specific rules regarding access to data. As concerns a European approach on distribution tariffs, the views are mixed; the usefulness of some general principles is acknowledged by many stakeholders, while others stress that the concrete design should generally considered to be subject to national regulation.

(iv) *Regulatory framework/electricity market governance*. Stakeholders' opinions with regard to strengthening ACER’s powers are divided. There is clear support for increasing ACER's legal powers by many stakeholders (e.g. oversight of ENTSO-E activities or decision powers for swifter alignment of NRA positions). However, the option to keep the *status quo* is also visibly present, notably in the submissions from Member States and national energy regulators. While some stakeholders mentioned a need for making ACER'S decisions more independent from national interests, others highlighted rather the need for appropriate financial and human resources for ACER to fulfil its tasks.

Stakeholders' positions with regard to strengthening ENTSO-E remain divided. Some stakeholders mention a possible conflict of interest in ENTSO-E’s role – being at the same time an association called to represent the public interest, involved e.g. in network code drafting, and a lobby organisation with own commercial interests – and ask for measures to address this conflict. Some stakeholders have suggested in this context that the process for developing network codes should be revisited in order to provide a greater a balance of in interests. Some submissions advocate for including DSOs and stakeholders in the network code drafting process.

A majority of stakeholders support governance and regulatory oversight of power exchanges, particularly in relation to their role in market capacity. Other stakeholders are skeptical whether additional rules are needed given the existing rules in legislation on market coupling (CACM Guideline).

Stakeholders mention also that the role of DSOs and their governance should be clarified in an update to the 3rd Package.

(v) *Regionalisation of System Operation*. As concerns the proposal to foster regional cooperation of TSOs, a clear majority of stakeholders is in favour of closer *cooperation* between TSOs. Stakeholders mentioned different functions which could be better operated by TSOs in a regional set-up and called for less fragmentation in some important of the work of TSOs. Around half of those who want stronger TSO cooperation are also in favour of regional decision-making

responsibilities (e.g. for Regional Security Coordination Centres). Views were split on whether national security of supply responsibility is an obstacle to cross-border cooperation and whether regional responsibility would be an option.

Public consultation on risk preparedness in the area of security of electricity supply

A public consultation on risk preparedness in the area of security of electricity supply was organized between July 15th and October 9th 2015. This public consultation aimed at obtaining stakeholder's views in particular on how Member States should prepare themselves and co-operate with others, with a view to identify and manage risks relating to security of electricity supply.

The consulation resulted in 75 responses including public authorities (e.g. Ministries, NRAs), international organizations (e.g. IEA), European bodies (ACER, ENTSO-E) and most relevant stakeholders, including SMEs, industry and consumers associations, companies and citizens. The following paragraphs provide a summary of the responses.

The responses themselves as well as a summary thereof are also available on the Commission's website[8].

(i) *Obligation to draw up risk preparedness plans*. A large majority of respondents (75 %) is in favour of requiring Member States to draw up risk preparedness plans, covering results of risk assessments, preventive measures as well as measures to be taken in crisis situations.

There is also a large support for having common templates, which should ensure that a common approach is followed throughout Europe. Many respondents stress the need for common definitions, common assessment methods, and common rules on how to ensure security of supply.

In fact, most respondents acknowledge that in an increasingly interconnected electricity market, characterised by an increasing amount of variable supply, security of supply should be considered a matter of common concern (countries are increasingly dependent on one another and measures taken in one country can have a profound effect on what happens in neighbouring states and in electricity markets in general). They also acknowledge that the current legal framework (Directive 89/2005) does not offer the right framework for addressing this inter-dependence. Therefore, they take the view that risk preparedness plans based on common templates can help ensure that each Member State takes the measures needed to ensure security of supply whilst co-operating with and taking account of the needs of others. Stakeholders, in particular from the industry, also stress that risk preparedness plans should help ensure more transparency and reduce the scope for measures that unnecessarily distort markets.

Whilst acknowledging the need for a common approach, a significant number of stakeholders also state that there should be sufficient room for tailor-made,

8 https://ec.europa.eu/energy/en/consultations/public-consultation-risk-preparedness-area-security-electricity-supply

national responses to security of supply concerns, as there are substantial differences between national electricity systems.

Respondents further agree that plans should be drawn up on a regular basis, proposals range from 2 to 5 years. The degree of transparency of the plans should depend on its content and may vary in function of it (given the fact that plans contain possibly sensitive information). Finally, respondents also warn against creating new administrative burdens and on this basis argue that any obligation to make risk preparedness plans should take account of already existing assessment and reporting obligations.

The minority of stakeholders taking the view that there should be no new legal obligation to draw up risk preparedness plans argue that such plans are already in place at the national level, that national electricity systems are profoundly different from one another and that priority should be given to the process of adopting network codes and guidelines.

(ii) *Content of risk preparedness plans / substantive requirements plans should comply with.* Many stakeholders take the view that it is too early at this stage to decide on the exact content of risk preparedness plans. They stress the need for more analysis, as well as in-depth discussions on the issue, in particular within the Electricity Coordination Group. In spite of this general caveat, consultation results already contain many useful pointers about substantive requirements plans should comply with:

- Definition of risks. Various stakeholders stress the need to develop a common definition of what security of supply means and the various risks that should be covered. Risk preparedness plans should be comprehensive in nature, covering generation adequacy and grid adequacy issues, as well as issues related to more short-term security issues (such the risk of a sudden unavailability of the grid or a power plant as a result of a terrorist attack);

- Cybersecurity. Respondents generally acknowledge the importance of preventing risks related to cyber-attacks but there is at this stage, no agreement on the need for further specific EU measures;

- Risk assessments and standards. Whilst the public consultation did not raise a specific question on risk assessment methods and standards (since these questions where covered by the market design consultation), various stakeholders make the case for a common methodology for assessing risks, to ensure a comparability of results, and a more common and transparent approach to the standards that are used to assess risks and define an acceptable level of reliability (this is also confirmed by replies to the market design consultation). Various stakeholders also take the view that risk preparedness plans should contain the results of various assessments made as well as the indicators used to make the assessments;

- Preventive measures. Stakeholders in favour of risk preparedness plans agree that such plans should identify both demand-side and supply-side measures taken to prevent security of supply issues, in particular situations of scarcity. They also agree on the need to assess the impact of existing and future interconnections and to take account of the import capacity when designing preventive measures. Many stakeholders point in this context to the need to ensure that markets function in an optimal way, thus allowing for flexibility in demand and a mix of solutions to ensure that a sufficient level of supply is guaranteed whilst keeping distortive measures at bay. Finally, stakeholders also stress that any assessment of import capacity should take account of the expected situation in neighbouring Member States;

- Dealing with emergency situations. A large majority of stakeholders agrees that plans should identify actions (market and non-market based) to be taken in emergency situations and rules on cooperation with other Member States. A majority also believes that plans should include provisions on the suspension of market activities, "protected customers" and cost compensation. Additionally, some stakeholders suggest lists of specific content for the emergency plans. As regards the development of new EU rules, many stakeholders state that due account should be taken of the network code on Emergency and Restoration, which is under preparation. Most say this draft network code should be considered as the basis, whilst acknowledging a possible need for additional common rules. A minority of stakeholders argues that the network code on emergency and restoration should be considered sufficient, leaving no need for additional EU-level rules, or consider that the issues not covered by the network code should not be addressed at the EU level;

- Definition/clarification of roles and responsibilities and what operational procedures to be followed (e.g., who to contact in times of crisis)

(iii) *Who should draw up risk preparedness plans, at what level, and with what kind of 'oversight'?*

- Who should be responsible for drawing up risk preparedness plans? Whilst most stakeholders recall that national governments have the ultimate responsibility for ensuring security of supply, many stakeholders consider that TSOs should take a lead role in drawing up risk preparedness plans. Most however consider that TSOs need to co-operate however with national ministries and/or national regulatory authorities, with the latter assuming a monitoring or supervisory role. There is a large support for a stronger DSO involvement in the preparation of the plans as well, as well as a clarification of the responsibilities of DSOs in crisis situations. Whilst most stakeholders see the added value of designating one 'competent authority' per Member States, there is no agreement on who that competent authority should be (and some argue that this choice should be left with the Member States).

- At what level should risk preparedness plans be drawn up? A large majority of respondents take the view that plans should be made at national level; however a large majority also stresses the need for more cross-border cooperation, at least in a regional context. A significant group of respondents argues that plans should be made at the regional level (for instance, as a complement to cross-border co-operation by TSOs in the frame of the regional security coordination initiatives) or call for plans at national and regional levels (or even 'multi-level' plans).[9] Those that argue in favour of national plans highlight the fact that responsibilities (and liabilities) for security of supply issues are national.[10] There is no agreement on how to 'define' regions for planning / co-operation purposes; most stakeholders suggest that synchronous areas and/or existing (voluntary) systems of regional co-operation should be used as a starting point. Finally, whilst only a minority calls for European plans, many see the need for some degree of co-ordination / alignment of plans in a European context (in particular via the development of common rules and peer reviews leading to best practice).

- What oversight should there be? Most stakeholders are in favour of a system of peer reviews, to be conducted either in a regional context, or in the frame of the Electricity Coordination Group. The latter should in any event be convened on a regular basis to serve as a forum for exchanging best practice. Some stakeholders are also in favour of a stronger role for ACER/ENTSO-E, in particular as regards more technical aspects of cross-border co-operation. As regards the Commission, stakeholders mainly see a facilitating role, but are often not in favour of a review system where the Commission takes binding decisions.

Aspects of the present initiative were also part of the consultation on the preparation of a **new Renewable Energy Directive** for the period after 2020[11] which was conducted from 18 November 2015 to 10 February 2016. It was open to EU and Member States' authorities, energy market participants and their associations, SMEs, energy consumers, NGOs, other relevant stakeholders and Citizens. The objective of this consultation was to consult stakeholders and citizens on the new renewable energy directive (RED II) for the period 2020-2030, foreseen before the end of 2016. The bioenergy sustainability policy, which will form part as well of the new renewable energy package, will be covered by a separate public consultation. The stakeholder responses to this consultation are descibed in more detail in the RED II impact assessment. A summary of the responses is however also available on the Commission's website[12].

Targeted consultations

A High Level Conference on electricity market design took place on 8 October 2015 in Florence.

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9 The rather cautious reaction to the idea of regional plans contrasts with the overwhelming support for regional assessments of generation adequacy under the market design consultation.

10 A similar concern is reflected in the market design consultation results.

11 https://ec.europa.eu/energy/en/consultations/preparation-new-renewable-energy-directive-period-after-2020

12 https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

The European Electricity Regulatory Forum convenes once or twice a year. The market design initiative was discussed in this stakeholder forum at several occasions, notably the Forum[13] that took place on 4-5 June 2015, 9 October 2015, 3-4 March 2016 and 13-14 June 2016.

The consumer- and retail- related aspects of the market design initiative were also discussed at the 8th Citizens' Energy Forum, which took place in London on 23 and 24 February 2016. The Commission established the London Forum to explore consumers' perspective and role in a competitive, 'smart', energy-efficient and fair energy retail market. It brings together representatives of consumer organisations, energy regulators, energy ombudsmen, energy industries, and national energy ministries.

The Electricity Coordination Group provide a platform for strategic exchanges between Member States, national regulators, ACER, ENTSOE and the Commission on electricity policy. This group was used to discuss issues related to the present impact assessment on 16 November 2015 and 3 May 2016.

On demand response two specifc stakeholder workshops were organised by the Commission: (i) Workshop on Status, Barriers and Incentives to Demand Response in EU Member States, organised be the European Commission on 23 October 2015, and (ii) Smart Grids Task Force, Expert Group 3 workshop on market design for demand response and self-consumption, March 2, 2016; and Expert Group 3 workshop on smart homes and buildings, April 26, 2016.

Member States' views

The support of Member States to the proposed initiatives is also apparent for instance from:

- The *"Council conclusions on implementation of the Energy Union"* of June 2015. In this regard, the conclusions state that: "*While STRESSING the importance of establishing a fully functioning and connected internal energy market that meets the needs of consumers, REAFFIRMS the need to fully implement and enforce existing EU legislation, including the Third Energy Package; the need to address the lack of energy interconnections, which may contribute to higher energy prices; the need for appropriate market price signals while improving competition in the retail markets; the need to address energy poverty, paying due attention to national specificities, and to assist consumers in vulnerable situations while seeking appropriate combination of social, energy or consumer policy; the need to inform and empower consumers with possibilities to participate actively in the energy market and respond to price signals in order to drive competition, to increase both supply-side and demand-side flexibility in the market, and to enable consumers to control their energy consumption and to participate in cost-*

[13] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_WORKSHOP/Stakeholder%20Fora/Florence_Fora

effective demand response solutions for example through smart grids and smart metres."[14]

- The *"Messages from the Presidency on electricity market design and regional cooperation"* of April 2016.[15] In these messages, the Presidency acknowledges the challenges facing the electricity markets in Europe and emphasizes, inter alia: the need to strengthen the functioning of the internal energy market; that correct price signals in all markets and for all actors are essential; that an integrated European electricity market requires well-functioning short-term markets and an adequate level of cross-border cooperation with regard to balancing markets; that security of supply would benefit from a more coordinated and efficient approach; that the future electricity retail markets should ensure access to new market players and facilitate introduction of innovative technologies, products and services.

Adherence to minimum Commission standards

The minimum Commission standards were all adhered to.

[14] http://data.consilium.europa.eu/doc/document/ST-9073-2015-INIT/en/pdf
[15] http://data.consilium.europa.eu/doc/document/ST-7879-2016-INIT/en/pdf

Annex III: Who is affected by the initiative and how

The present initiative covers a large area of measures. The tables below provide an overview of the parties affected, separately for each of the measures resulting from the preferred policy options developed in the Annexes 1.1 through to 7.6.

Such matters are equally referred to in section 6 of the main text for the (more aggregated) main policy options developed there.

Table 1. Persons affected by measure for Problem Area I, Option 1(a) (level playing field)

Affected party	Measure		
	1.1. Priority access and dispatch	**1.2. Regulatory exemptions from balancing responsibility**	**1.3. RES E access to provision of non-frequency ancillary services**
Member States	Need to change national legislation in so far as it contains priority dispatch; need to include provisions on transparency and compensation of curtailment and redispatch	Need to change national legislation in so far as it contains exemptions from balancing responsibility	They need to adapt national legislation to create conditions for non-discriminatory procurement of non-frequency ancillary services.
National regulatory authorities (NRAs)	Need to oversee implementation of provisions, notably determination which generators continue to benefit from priority rules, and ensure correct curtailment compensation.	Need to oversee implementation of provisions, notably oversight of TSOs.	They need to oversee implementation and monitoring of provisions, notably oversight of TSOs.
Transmission System Operators (TSOs)	Reduction of priority dispatch and priority access facilitates grid operation and lowers dispatch costs. Introduction of clear compensation rules on the other hand can increase redispatch costs where such compensation is currently insufficient.	Implementation of balancing rules, notably settlement of parties in imbalance.	They need to change the way non-frequency ancillary services are contracted, procured and possibly remunerated.
Distribution System Operators (DSOs)	Where DSOs curtail generation to resolve local grid constraints, they are affected identically to TSOs.	No direct impact, as balancing is the role of TSOs; indirectly, increased balancing responsibility of generators increases system transparency also to the benefit of DSOs.	DSOs very likely would also be affected, because most RES are connected at distribution level and the DSO's role in managing their network would have to change in order to allow RES assets to participate to the provision of ancillary services.
Generators	Generators currently subject to priority rules will be exposed to increased curtailment risks and lower likelihood of dispatch (for high marginal cost generators; likelihood of dispatch actually increases for low marginal cost generators) unless they continue to benefit from the exemptions. Generators not subject to exemptions will be less likely to be curtailed and more likely to be dispatched where they are the most efficient generator available. All generators will benefit from increased transparency and legal certainty on redispatch and curtailment compensation.	Balancing responsible parties, including suppliers, traders and generators currently subject to balancing responsibility are not directly impacted. Generators currently exempted or partly shielded from balancing responsibility will have to increase their efforts to remain in balance (e.g. through better use of weather forecasts) or will be exposed to financial risks.	Owners of generation assets (RES and not) would be affected by changes in the rules of how non-frequency ancillary services are procured. More transparent and competitive procurement rules could enable market entrance by new actors and technologies, such as battery storage.
Suppliers	Suppliers are not directly affected.	Balancing responsible parties, including suppliers, traders and generators currently subject to balancing responsibility are not directly impacted.	Most likely not affected.
Power exchanges	Power exchanges could benefit from the increased market liquidity particularly for short-term products which results from market-based curtailment and redispatch.	Power exchanges could benefit from the increased market liquidity particularly for short-term products which results from balancing responsibility of RES E.	Most likely not affected.
Aggregators	Aggregators are likely to benefit in particular by offering market-based resources to be used by TSOs in redispatch or curtailment.	Aggregators are likely to benefit in particular by offering to small generators services to fulfil their balancing responsibility.	Aggregators are likely to benefit from a more level playing field and get access to additional remuneration streams.
End consumers	End consumers are not directly affected.	End consumers are not directly affected.	End consumers are not directly affected.

Table 2. Persons affected by measure for problem Area I, Option 1(b) (Strengthening short-term markets)

Affected party	Measure		
	2.1. Reserves sizing and procurement	**2.2. Removing distortions for liquid short-term markets**	**2.3. Improving the coordination of Transmission System Operation**
Member States	Member State authorities define the country's overall policy regarding energy mix and power grid investments.	Member States authorities generally play a limited direct role in the operation of intraday markets. They will, however be impacted if they are responsible for implementing/enforcing requirements.	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements. This topic is likely to have a particularly political angle, as Member States may not be willing to entrust ROCs with decision-making powers under the assumption that security of supply is a national responsibility (although based on the TFEU, it constitutes a shared responsibility between the EU and MS).
National regulatory authorities (NRAs)	NRAs approve the methodology for sizing and procurement of balancing reserves. They are also responsible for any impact on TSOs' tariffs and how cross-border infrastructure is allocated.	NRAs are responsible for regulatory oversight of intraday markets, including as part of the implementation of the CACM Guideline, where they are responsible for approving a number of methodology developed by TSOs and power exchanges. They will, therefore, be affected by changes in so far as it could alter the basis for their regulatory decisions. However, the direct impact on NRAs is anticipated to be relatively limited.	NRAs of each of the regions where a ROC is established would be required to carry out the regional oversight of the concerned ROC. This would include competences at least equivalent to those established for NRAs in the Third Energy Package. It may be necessary to entrust ACER with the EU-wide oversight of ROCs. It would be necessary to set out a framework for the interaction between the regional groupings of NRAs and ACER.
Transmission System Operators (TSOs)	TSOs analyse system's state and propose the methodology for sizing and procurement of balancing reserves in their control areas. Shifting responsibilities for sizing and procurement of balancing reserves at regional level implies a need for strong governance at regional level. Existing physical constraints would still need to be taken into account in the regional procurement platform. Major impacts are expected on the current design of system operation procedures and responsibilities. Cost allocation and remuneration would have to be agreed, requiring the development of a clear and robust framework of responsibilities between national and regional TSOs.	TSOs are heavily involved in the operation of intraday markets, notably in determining the cross-border capacity made available to the market, and in using the results for operation of the system. They are therefore likely to be significantly impacted by any changes.	National TSOs would be complemented by ROCs performing functions of regional relevance, whilst real time operation functions would be left solely in the hands of national TSOs. ROCs could potentially be entrusted with certain decision making responsibilities for a limited number of operational functions, whilst TSOs would retain their responsibility as regards all other functions for which they are currently responsible at national level. It may be necessary to entrust additional tasks to ENTSO-E related to the cooperation and coordination between ROCs.
Generators	Generators, as Balancing Service Providers, would have additional opportunity to participate in the balancing market even though significant operational impact might increase due to the procurement frequency. Such framework would, however, allow the participation of renewable energy sources in the balancing market potentially leading to a sharp decrease of balancing reserve cost.	Generators will be affected by any changes in wholesale prices they receive for their energy on the intraday market. More efficient price signals, and more potential for trading, will open up the market to smaller generators, particularly renewable.	Generators could benefit from a more secure power system and a more efficient market leading to increased market opportunities.
Aggregators	Smaller products and time units will give aggregators more access to intraday markets.	Increased price fluctuations will give aggregators more opportunities to operate, thereby helping to ensure that demand meets supply at any point in time.	Limited impact on aggregators.
Suppliers	Regional procurement of reserves would lead to regional settlement of imbalances; therefore allowing for increase competition of suppliers across borders.	Suppliers will be affected insofar as they are the ones who buy power on the wholesale market. Any changes in intraday clearing prices will change how much they pay for their power, the extent to which will depend on how much trading they do in the intraday market.	Limited impact on suppliers.
Power exchanges	In case an optimisation process for the allocation of transmission capacity between energy and balancing markets has to developed, day-ahead market coupling algorithm currently operates by power exchanges might be	Power exchanges will be the most affected by any changes to intraday arrangements, as they are the ones who operate the platforms on which energy is traded in the intraday timeframe. They will therefore have to adapt systems and process to meet new requirements.	Limited impact on power exchanges. It is expected that they could benefit power exchanges as the optimisation of market-related functions such as capacity calculation would entail more liquidity in the markets that could be exchanged.

Affected party	Measure		
	2.1. Reserves sizing and procurement	**2.2. Removing distortions for liquid short-term markets**	**2.3. Improving the coordination of Transmission System Operation**
	impacted and solution will have to be found on sharing transmission capacity in an optimal way for the markets preceding the balancing market.		
End consumers	End consumers will be able to participate in balancing markets via demand response aggregators allowing for stronger supplier's competition at regional level.	End consumers will be affected insofar as changes to the wholesale price are passed on to them in their retail price.	Regional TSO cooperation through the creation of ROCs would benefit consumers through improved security of supply (by minimising the risk of wide area events such as brownouts and blackouts), and lowering costs through increased efficiency in system operation and maximised availability of transmission capacity to market participants.

Table 3. Persons affected by measure for Problem Area I, Option 1(c) (Pulling demand response and distributed resourced into the market)

Affected party	Measure			
	3.1. Unlocking demand side response	**3.2. Distribution networks**	**3.3. Distribution network tariffs and DSO remuneration**	**3.4. Improving the institutional framework**
Member States	Those 17 Member States that roll out smart meters will not be affected by the new provisions on smart meters, apart from the obligation to comply with the recommended functionalities, which may need to transpose into national legislation. Similarly for those two Member States that opted for partial roll-out and are not expected to face any other additional burden from allowing additional consumers to request smart meters. However, those 9 Member States that currently do not plan to install any smart meters will need to establish legislation with technical and functional requirements for the roll-out and face some additional administrative impact by re-evaluating their cost-benefit analyses. What concerns market rules for demand response, Member States are already obliged through the EED to enable demand response. The new provisions will rather provide additional guidance for Member States on how to create the enabling framework instead of imposing additional burden to them.	The competent ministries in each Member State who will be involved in the transposition of the relevant EU legislation and monitor the implementation and effectiveness of the measures under the preferred option.	The competent ministries in each Member State who will be involved in the transposition of the relevant EU legislation and monitor the implementation and effectiveness of the measures under the preferred option.	MS authorities will be in charge of national implementation of the revised Third Package.
National regulatory authorities (NRAs)	Additional administrative impact may be created for the NRAs for enforcing actions regarding the consumer entitlement to request a fully functional smart meter. This includes assessing the costs to be borne by the consumer, and overseeing the process of deployment. At the same time, improved consumer engagement thanks to smart metering, would make it easier for NRAs to ensure proper functioning of the national (retail) energy markets. Already under the existing legislation NRAs are obliged to encourage demand side resources to participate alongside supply in markets. The new provisions under the preferred option only further specify which aspects have to be addressed by NRAs but they do not create additional burden for them.	As DSOs are regulated entities is expected that NRAs will have the main role of ensuring the effective application of measures. NRAs will be mostly involved in the application of the measures and in designing the necessary rules for the practical implementation. As the measures under the preferred option are closely linked to a suitable remuneration methodology, NRAs will also probably have to modify existing schemes. This will require the availability of the necessary human, technical and financial resources.	According to the Electricity Directive NRAs have the main role in fixing or approving network tariffs or their methodologies. The overall aim is to move towards more sophisticated network tariff methodologies. To this end, some NRAs might have to modify the existing methodologies for distribution tariffs. The introduction of smarter regulatory frameworks will require the availability of the necessary human, technical and financial resources.	Their role, powers and responsibilities will be further clarified, especially as regards issues which are relevant at regional/EU level. This will affect the way NRAs have cooperated at regional and EU-level, including within ACER, in order to enhance the collaboration between NRAs and ACER. In the context of clarifying the respective roles of NRAs and ACER, some of the powers and responsibilities currently conferred to NRAs may be shifted to ACER.
Agency for the cooperation of energy regulators (ACER)	Apart from the minor changes necessary to ensure effective market monitoring in the changed market context, ACER will not be affected by changes in unlocking demand side response..	ACER will be affected to the extent which will be called to oversight the activities of EU DSO entity and its involvement in relevant network codes or guidelines.	ACER will be affected to the extent which will be called to oversight the activities of EU DSO entity and its involvement in network codes or guidelines on network tariffs.	Its role, powers and responsibilities will be further enhanced in order to ensure that ACER can continue fulfilling its role of supporting NRAs in exercising their functions at EU level and to coordinate their actions where necessary. For a number of specific and defined instances, some of the powers and responsibilities of NRAs will be shifted to

Affected party	Measure			
	3.1. Unlocking demand side response	3.2. Distribution networks	3.3. Distribution network tariffs and DSO remuneration	3.4. Improving the institutional framework
				ACER, to ensure that it can carry out an EU-level oversight. ACER's role will be affected by the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines.
Transmission System Operators (TSOs)	A greater roll-out of smart meters allows TSOs to better calculate settlements and balancing penalties as the consumption figures can be based on real consumption data and not only on profiles. TSOs are affected by opening markets for aggregated loads and demand response. Those effects are dealt with in the Impact Assessment on markets. TSOs are not directly affected by the proposed measures on removing market barriers for independent aggregators. However, they are indirectly affected: A greater participation of flexibility products in ancillary service markets (e.g. balancing markets) can help TSOs cost-effectively manage the network.	TSOs will be involved as more coordination with DSOs will be required. TSOs will have to allocate the necessary human and technical resources in order to achieve such coordination.	TSOs will not be affected by changes in distribution tariffs.	Some of the transparency obligations imposed on ENTSO-E as well as some of the governance rules applying to this association will indirectly affect TSOs. Some of the proposed rules (e.g. co-financing of ACER by contributions from market participants) might directly impact on TSOs.
European network of transmission system operators (ENTSOs)	ENTSO-E will not be affected by changes in unlocking demand response.	ENTSO-E will have to cooperate with the EU DSO entity on issues which are relevant to both transmission and distribution networks.	ENTSO-E will not be affected by changes in distribution tariffs.	ENTSO-E's mandate will be mainly clarified, whilst ensuring that its added value of providing technical expertise is preserved. Transparency of ENTSO-E will be further improved. The role of ENTSO-E will be affected by the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines.
Distribution System Operators (DSOs)	In most Member States, DSOs are responsible for organising the installation of smart meters. The additional costs to be determined by the NRAs can however be charged to the users. DSOs also benefit from access to real time data coming from smart metering. It supports them in their work on monitoring and controlling the network, improving its reliability and power quality, and its overall effectiveness, particularly in the presence of distributed generation. This ultimately contributes to the increased distribution network efficiency and increased revenue for the DSOs (e.g. via reduced technical and commercial losses) DSOs are not directly affected by the proposed measures on removing market barriers for independent aggregators. However, DSOs can	DSOs will be directly affected by the possible measures under the preferred option as they will have to have in place the necessary human and technical resources in order to implement the envisaged measures. Additional personnel or infrastructure might be necessary. However, DSOs will use flexibility solutions in order to increase efficiencies, only where benefits will outweigh additional costs.	It is expected that the envisaged measures under the preferred option will positively affect DSOs as they aim to a more efficient utilisation of the distribution system and the incentivisation of DSOs towards more optimal development and operation of their grids. More advanced tariff schemes may require the availability and monitoring of detailed data (financial and technical) and the achievement of specific targets. Any additional administrative costs should be offset by the expected benefits.	DSOs will be able to participate more actively as a result of the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines.

Affected party	Measure			
	3.1. Unlocking demand side response	**3.2. Distribution networks**	**3.3. Distribution network tariffs and DSO remuneration**	**3.4. Improving the institutional framework**
	indirectly benefit from a better uptake of demand response as the reduction in peaks it will reduce the need to invest in distribution networks.			
Generators	Demand response is designed to reduce peak demand and thereby effectively replace marginal power plants and reduce electricity prices at the wholesale market. As such generators are likely to face reduced turnover from lower peak prices and from operating reserve capacities. Generators are not likely to be effected by an accelerated smart meter roll out.	Generators will not be affected by the measures under the preferred option.	The envisaged measures aim to the overall reduction of network costs through the incentivisation of DSOs to raise efficiencies, which will have an overall positive impact to system users. The envisaged measures also aim to a fair allocation of costs among different system users. Therefore, to the extent to which the envisaged measures will incite changes in existing tariffs, generators or other system users may be affected from any new tariffs which will result to reallocation of costs.	Generators will be able to participate more actively as a result of the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines.
Suppliers	Smart meters can have a direct impact on suppliers, as they enable consumers to easily switch. Furthermore, there is one Member State where suppliers are responsible for the roll-out. Moreover, smart metering allows suppliers to offer dynamic pricing contracts that reduce suppliers' risk of changing wholesale prices. The effect of demand response on suppliers can be positive as suppliers will benefit from lower wholesale prices. On the other hand demand response will make it more difficult for suppliers to calculate retail prices. Also as balancing responsible parties they may face higher penalty payments for imbalances incurred due to their customers changing consumption patterns. Finally, new competition from aggregators may reduce their income. However, suppliers can also offer demand response services to their customers and expand their range of services and thereby turnover. The overall financial impact of smart meters and of more competition through demand response on suppliers will hence depend on the ability of the individual supplier to adapt to the new market with innovative services and competitive pricing offers.	Suppliers will not be affected as the envisaged measures will not affect their normal business.	It is not expected that the envisaged measures will affect the suppliers.	Suppliers will be able to participate more actively as a result of the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines.
Power exchanges	No impact expected	No impact expected	No impact expected	Power exchanges will be subject to an enhanced regulatory oversight at EU level exercised by ACER and NRAs. Power exchanges will be able to participate more actively as a result of the changes envisaged for the process of development of Commission implementing regulations in the

Affected party	Measure			
	3.1. Unlocking demand side response	3.2. Distribution networks	3.3. Distribution network tariffs and DSO remuneration	3.4. Improving the institutional framework
				form of network codes and guidelines.
Aggregators (and other new market entrants)	Aggregators are likely to benefit from an accelerated roll out of smart meters as this technology facilitates market access for demand service providers and aggregators. Equally all measures aimed at removing market barriers and increasing competition in the retail market will immediately facilitate market access for aggregators and new energy service providers and hence opens new business opportunities for them.	Aggregators will be positively affected as DSOs will request their services in order to use flexibility for managing congestion in their networks.	Insofar as distribution tariffs incentivise grid users to use the network more efficiently, aggregators will not be called upon as much to help to manage network congestion..	Aggregators and other new market entrants will be able to participate more actively as a result of the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines
End consumers	End consumers will get the right to request smart meters and have access to dynamic electricity pricing contracts which clearly gives puts them in a position to become active market participants. Furthermore, provision of accurate and reliable data flows due to smart metering would enable easier and quicker switch between suppliers, access to choices, smart home solutions and innovative automation services, and can also lead to energy savings. Consumers will equally benefit from more competition, wider choice, and the possibility to actively engage in price based and incentive based demand response and hence from reduced energy bills. But also those consumers who do not engage themselves in demand response can profit from lower wholesale prices as a result of demand response if those price reductions are being passed on to consumers.	Use of flexibility from DSOs will result to lower network costs. This reduction will be reflected in distribution tariffs and the final electricity bill of the consumer.	The envisaged measures aim to the overall reduction of network costs through the incentivisation of DSOs to raise efficiencies, which will have an overall positive impact to system users. The measures also aim to a fair allocation of costs among different system users. Therefore, to the extent to which the envisaged measures will incite changes in existing tariffs, consumers or other system users may be affected from any new tariffs which will result to reallocation of costs.	Consumers will be able to benefit from enhanced transparency and in general from well-functioning energy markets.

Table 4. Persons affected by measure Problem Area II, Option 1 (Improved energy market without CMs)

Affected party	Measure			
	4.1. Removing price caps	**4.2. Improving locational price signals**	**4.3. Minimise investment and dispatch distortions due to transmission tariff structures**	**4.4. Congestion income spending to increase cross-border capacity**
Member States	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements.	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements. This topic is likely to have a particularly political angle, as splitting price zones within a Member State will result in different wholesale electricity in that Member State depending on location (although not necessarily retail prices).	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements.	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements.
National regulatory authorities (NRAs)	NRAs will be impacted if they are responsible for implementing/enforcing/monitoring the requirements.	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements.	NRAs play a significant role in monitoring, authorising, etc. tariffs and connection charges. Any change would impact on how they do this.	NRAs are currently responsible for reviewing the use of congestion income, and for authorising it to be spent on the reduction of tariffs. They will be affected by Option 2 and 3 as they no longer need to authorise it to be spent on the reduction of tariffs. Option 1 could require them to make a more them to make a more thorough assessment. ACER will be affected by changes to monitoring and transparency requirements and the requirement on them to develop harmonised rules.
Transmission System Operators (TSOs)	There will be limited impact on TSOs.	TSOs will be affected as it will likely mean they hold and operate networks over more than one price zone. It will also change those transmission lines that accumulate revenue from congestion.	Changes would have limited impact on TSOs themselves, as proposals are not generally looking at how TSOs are remunerated, but rather how the money is collected.	It will change how transmission system operators are able to use congestion income. Options 1-3 could lead to more investment activity of the TSO.
Generators	Increased price variability will impact the revenue generators will see from the energy market – they will likely see higher prices for short periods of time, which will incentivise flexible generation.	Different price zones will change the prices that generators receive depending on their location.	Changes would most affect generators – lower connection charges or tariffs (where they are applied to generators) would have a positive impact on their revenues.	If Option 1, 2 and 3 lead to more investment in networks, this would impact generators by delivering more cross-border competition and present further trading opportunities to sell energy by an increases in the liquidity of cross-border markets.

Affected party	Measure			
	4.1. Removing price caps	**4.2. Improving locational price signals**	**4.3. Minimise investment and dispatch distortions due to transmission tariff structures**	**4.4. Congestion income spending to increase cross-border capacity**
Suppliers	Increased price variability will impact the price paid by suppliers - – they will likely see higher prices for short periods of time.	Different price zones will change the prices that suppliers pay depending on their location.	Limited impact on suppliers.	If Option 1, 2 and 3 lead to more investment in networks, this would impact generators by delivering more cross-border competition and present further trading opportunities to buy energy by an increase in the liquidity of cross-border markets.
Power exchanges	Power exchanges will be required to implement the requirements, which could require changes to systems and practices.	Different price zone will change the practices of power exchanges – currently they operate based on MS-level markets (in general) – they would need to differential markets based on different price boundaries.	Limited impact on power exchanges.	If Option 1, 2 and 3 lead to more investment in networks, this would impact power exchanges if it leads to greater cross-border trade on their platforms.
End consumers	End consumers will be affected insofar as changes to the wholesale price are passed on to them in their retail price. However, more variable prices will not necessarily be felt by end-consumers as they may be hedged (particularly household) against this volatility in their retail contracts.	Different price zones *could* affect end-consumers depending on their location. However, possibilities exist to retail MS-level retail prices,	End consumers could be affected if more tariffs were charged on load, as opposed to production. However, overall the impact is likely to be similar as the overall cost basis would not changing.	End consumers may be affected by any reduction in the amount that can be offset against tariffs. However, this may be outweighed by the positive effect of more cross-border capacity being available, and the benefit this has on competition and energy prices.

Table 5. Persons affected by measures of Problem Area II, Option 2 (Improved energy market, CMs based on an EU-wide adequacy assessment) and Option 3 (Improved energy market, CMs based on an EU-wide adequacy assessment, plus cross-border participation

Affected party	Measure	
	5.1. Improved generation adequacy methodology	**5.2. Cross-border operation of capacity mechanisms**
Member States	Member States would be better informed about the likely development of security of supply indicators and would have to exclusively rely on the EU-wide generation adequacy assessment carried out by ENTSO-E when arguing for CMs.	Each Member State would not need to design a separate individual solution – and this would potentially reduce the need for bilateral negotiations between TSOs.
National regulatory authorities (NRAs)	NRAs/ ACER would be required to approve the methodology used by ENTSO-E for the generation adequacy methodology and potentially endorse the assessment.	NRAs/ ACER would be required to set the obligations and penalties for non-availability for both participating generation/ demand resources and cross-border transmission infrastructure.
Transmission System Operators (TSOs)	TSOs would be obliged to provide national raw data to ENTSO-E which will be used in the EU-wide generation adequacy assessment.	ENTSO-E would be required to establish an appropriate methodology for calculating suitable capacity values up to which cross-border participation would be possible. Based on the ENTSO-E methodology, TSOs would be required to calculate the capacity values for each of their borders. They might potentially be penalized for non-availability of transmission infrastructure. TSOs would be required to check effective availability of participating resources. ENTSO-E may also be required to establish common rules for crediting foreign capacity resources for the purpose of participation in CMs reflecting the likely availability of resources in each country/zone.
Generators	ENTSO-E would also have to provide for an updated methodology with probabilistic calculations, appropriate coverage of interdependencies, availability of RES and demand side flexibility and availability of cross-border infrastructure.	Foreign capacity providers would participate directly into a national capacity auction, with availability rather than delivery obligations imposed on the foreign capacity providers and the cross-border infrastructure. Foreign capacity providers/ interconnectors would be remunerated for the security of supply benefits that they deliver to the CM zone and would receive penalties for non-availability.
Suppliers	ENTSO-E would be required to carry out an EU-wide or regional system adequacy assessment based on national raw data provided by TSOs (as opposed to a compilation of national assessments).	Limited impact on suppliers
Aggregators	With the updated methodology provided by ENTSO-E, intermittent RES generators/ demand-side flexibility would be less likely to be excluded from contributing to generation adequacy.	Just like generators they shall be able to participate in cross-border CMs.
Power exchanges	Limited impact on suppliers	Limited impact on power exchanges
End consumers	Limited impact on aggregators	Explicit cross-border participation in CMs would preserve the properties of market coupling and ensure that the distortions of uncoordinated national mechanisms are corrected and the internal market is able to deliver the benefits to consumers.

Table 6. Persons affected by measures for Problem Area III

Affected party	Measure
Member States	Member States (i.e. responsible ministries) would bear the main responsibility of preparing Risk Preparedness Plans and coordinating relevant parts with other Member States from their region, including ex-ante agreements on assistance during (simultaneous) crisis and financial compensation. Member States would designate a ministry or the NRA as 'competent authority' as responsible body for preparing the Risk Preparedness Plan and for cross-border coordination in crisis. As members of an empowered Electricity Coordination Group they would consult and coordinate Plans. The above described responsibilities might involve an increased administrative impact. However, most of the tasks are already carried out in a purely national context and there might also be benefits from exploiting synergies of improved cooperation. In addition, existing national reporting obligations would be reduced (e.g. repealing the obligation of Article 4 of Electricity Directive "Monitoring security of supply").
National regulatory authorities (NRAs)	NRAs could possibly fulfil certain tasks as part of the Risk Preparedness Plan of their Member State. Furthermore they might be appointed as 'competent authority' by Member States. In this case, they would be responsible for preparing the Risk Preparedness Plan and for cross-border coordination during crisis, possibly requiring additional resources.
Transmission System Operators (TSOs)	ENTSO-E would be responsible for identification of crisis scenarios and risk assessment in a regional context. A common methodology for short-term assessments (ENTSO-E Seasonal Outlooks and the week-ahead assessments of the RSCs) should be developed by ENTSO-E. This might require additional resources within ENTSO-E and within the RSCs, in case that ENTSO-E delegates all or part of these tasks to them. However, additional costs would be limited as some of these tasks are already carried out today. Giving these bodies a clear mandate, it would however significantly improve cross-border coordination.
Generators	Generation companies and other market participants would not be directly affected by preparation of Risk Preparedness Plans. However, they would benefit from clearer rules on crisis management and the prevention of unjustified market intervention.
Suppliers	Market participants would not be directly affected by preparation of Risk Preparedness Plans. However, they would benefit from clearer rules on crisis management and the prevention of unjustified market intervention.
Aggregators	Market participants would not be directly affected by preparation of Risk Preparedness Plans. However, they would benefit from clearer rules on crisis management and the prevention of unjustified market intervention.
Power exchanges	Market operators would not be directly affected by preparation of Risk Preparedness Plans. However, they would benefit from clearer rules on crisis management and the prevention of unjustified market intervention.
End consumers	As described above the impacts of blackouts on industry and society proved to be severe. Consequently, end consumers benefit extensively from improved risk preparedness as it would help to prevent future blackouts more effectively.

Table 7.a Persons affected by measure for Problem Area IV

Affected party	Measure		
	7.1. Monitoring energy poverty	**7.2. Options for phasing out regulated prices**	**7.3. Creating a level playing field for access to data**
Member States	Option 1 leads to an improved framework to measure energy poverty. Member States will have a better understanding of energy poverty as a result of a clearer conceptual framework (through the common understanding of energy poverty) and better information on the level of energy poverty (measuring energy poverty). Ultimately, this will contribute to better identification and targeted public policies to alleviate energy poverty.	Those Member States still practicing some form of price regulation will have to make the necessary legislative and market changes in order to ensure a smooth and effective phase out.	The competent ministries and authorities who will be involved in the transposition of the relevant EU legislation and will monitor the implementation and effectiveness of the measures under the preferred option.
National regulatory authorities (NRAs)	NRAs will need to monitor and report to the European Commission and ACER the number of disconnections. According to ACER Market Monitoring Report, only 16 Member States met this requirement.	In most countries with price regulation, NRAs are the bodies responsible for setting the level of regulated prices for a defined regulatory period. In few cases NRAs are only giving their opinion on regulated prices set by the government. Phasing-out regulated prices would remove these responsibilities of the NRAs therefore reducing administrative costs and resource needs. However new tasks for the NRAs might be defined by Member States in the follow-up of the price deregulation process such as monitoring the level of market prices with the possibility to intervene ex post in the price setting in case of market abuse. The costs of carrying out such new tasks are likely to be less important than the costs of setting regulated prices, resulting overall in reduces resource needs for the NRAs.	The envisaged measures will partly affect the NRAs as most probably will have a role in the implementation of the measures at national level. Other authorities such as data protection authorities may be involved in the implementation of the envisaged measures at national level. NRAs will have to monitor the data handling procedures as part of the retail market functioning. The involvement of NRAs is expected to be higher in Member States where smart metering systems are deployed.
Transmission System Operators (TSOs)	The preferred option would not directly affect TSOs.	The preferred option would not directly affect TSOs.	TSOs might be affected in terms of costs in cases where Member States will decide that they are responsible for the operation of the data-hub. However, the envisaged measures do not impose an obligation to Member States regarding the data management model and the party responsible for acting as a data-hub. The measures under the preferred option will benefit TSOs and other operators as the will allow them, under specific terms, to have access to aggregated information which will be useful for network planning and operation.
Distribution System Operators (DSOs)	The preferred option would not directly affect DSOs.	The preferred option would not directly affect DSOs.	In the large majority of Member States DSOs will be involved directly in the data handling process. DSOs will have the same benefits as TSOs in terms of system operation and planning. Under the preferred option DSOs which are not fully unbundled (DSOs below the 100.000 threshold) will have to implement measures which link to the non-discriminatory treatment of information. The implementation of such measures will most probably create costs which will vary depending on the national framework. It is not expected however that these costs will create a high burden, as they can implemented through automated IT systems.

Affected party	**Measure**		
	7.1. Monitoring energy poverty	**7.2. Options for phasing out regulated prices**	**7.3. Creating a level playing field for access to data**
Generators	The preferred option would not directly affect generators.	In countries where artificially low regulated end-user prices are backed up by generation deliveries at non cost-reflective level agreed by long-term contracts, deregulation of end user prices could trigger a rethinking of such system by a renegotiation of long-term contracts which would stimulate investment in efficient generation capacities with positive effects on the competition on the generation market.	Generators will not be affected under the preferred option.
Suppliers	The preferred option would not directly affect suppliers. However, should the improved monitoring of energy poverty lead to increased action to tackle the problem by Member States, then the costs of these measures may be borne by suppliers. Depending on each Member States, these costs may then be recovered as network charges, passed on to consumers or taken against energy providers overall benefits. Preventative measures, such as debt management or providing additional information on where to find support, represent an additional cost to energy retailers in those Member States where these measures are not yet in place. A moratorium of disconnection will reduce energy retailers' revenue as energy will be supplied free of charge. However, such costs will to some extent be mitigated by lower numbers of bad debtors in the long run.	Alternative (non-regulated) suppliers would benefit from the deregulation of prices by increased possibilities to compete on the price and therefore to gain more market share. This is particularly true for countries where regulated prices set at non cost-reflective levels prevent alternative suppliers from contesting the regulated offer. For the regulated suppliers (usually former incumbents) the removal of price regulation would lead to increased operational costs related to the implementation of the transition from the regulated offer to market based offer for its customer base. Moreover, regulated suppliers are likely to lose significant market shares if customers will switch to competitive offers of alternative suppliers.	The availability of consumption data under non-discriminatory terms and interoperability of data formats will have positive effects on suppliers and other retailers. The aim of the measures under the preferred option is to bring down the administrative costs for the various retail service providers including suppliers.
Power exchanges	The preferred option would not directly affect power exchanges.	The preferred option would not directly affect power exchanges. However, power exchanges could benefit from increased liquidity due to better functioning competition on retail and wholesale markets following price deregulation.	-
Aggregators	The preferred option would not directly affect aggregators.	Removing price regulation would stimulate the development of energy services which create market opportunities for aggregators.	In the preferred option aggregators and other retail service providers will have equal access to data as suppliers in a transparent and non-discriminatory way. This will allow aggregators to develop new services for consumers and will facilitate their entrance in the market.
Consumers	Consumers in a situation of energy poverty or at risk of energy poverty will be positively impacted by the preferred option. A clearer understanding and measuring of energy poverty will have positive impacts on Member States efforts to tackle energy poverty..	Phase-out of regulated prices for end customers would stimulate competition on retail markets which translates for customers into more choice and better offers in terms of price and service quality. Customers would be able to better manage their own energy consumption by using energy services and technologies such as demand response, self-generation, and self-consumption. However, notably in countries where prices are artificially regulated at low levels, price deregulation could be followed by substantial increases in end user prices; to help customers face such price increases, appropriate protection measures for vulnerable customers should be in place prior to deregulation.	The envisaged measures under the preferred option aim to support the development of a competitive retail market. It is expected that the measures will bring developments which will affect positively consumers through the availability of wider choice of services, focusing on demand response and energy efficiency.

Table 7.b Persons affected by measures for Problem Area IV

Affected party	Measure		
	7.4. Facilitating supplier switching	**7.5. Comparison Tools**	**7.6. Improving Billing Information**
Member States	The preferred option may need to be transposed into national law, resulting in administrative impacts. Some Member States (e.g. BE, IT) have eliminated exit fees already, the latter reporting increased consumer trust as a result. Others with a relatively high preponderance of exit fees (NL, IE, SI) are likely to be more reserved, particularly in light of the fact that they may have relatively competitive markets already.	The preferred option will need to be transposed into national law, resulting in administrative impacts. However, some 13 Member States already have at least one independent CT run by a government or government-funded body. As these are free of conflicts of interest, we can assume they are likely to meet the accreditation criteria.	The preferred option will need to be transposed into national law, resulting in modest implementation costs.
National regulatory authorities (NRAs)	The preferred option would likely lead to additional stakeholder engagement and enforcement actions, resulting in increased administrative impacts to NRAs. However, any clarification and simplification of EU legal provisions may lead to greater ease of enforcement, and commensurate savings. In addition, improved consumer engagement would make it easier for NRAs to ensure the proper functioning of national (retail) energy markets they are charged with.	The preferred option would likely lead to additional stakeholder engagement and enforcement actions, resulting in increased administrative impacts. However, this would not necessarily be a role for the NRAs as an independent body might be assigned the task (e.g. GB where an independent auditor audits the CT). However, any strengthening of EU legal provisions should lead to a reduction in the number of consumer complaints. In addition, improved consumer engagement would make it easier for NRAs to ensure the proper functioning of national (retail) energy markets.	The preferred option would likely lead to additional stakeholder engagement and enforcement actions, resulting in increased administrative impacts to NRAs. However, improved billing clarity would make it easier for NRAs to ensure the proper functioning of national (retail) energy markets they are charged with.
Transmission System Operators (TSOs)	Not affected.	Not affected.	Not affected.
Distribution System Operators (DSOs)	Any change in consumer switching behaviour resulting from the preferred option would be reflected in switching operations, and their associated administrative impacts. However, as DSOs are regulated monopolies, these costs (or savings, if switching decreases) will eventually be passed through to end consumers.	Insofar as the measures lead to increased switching, this will result in increased administrative costs to DSOs. However, these costs will be passed through to consumers through network charges.	Not affected.
Suppliers	Most suppliers are unlikely to welcome measures to further restrict switching-related fees, as these limit their ability to tailor tariffs to different consumers. Some may also financially benefit from the increased 'stickiness' switching-related fees create amongst their consumer base. In addition, any change in consumer switching behaviour resulting from the policy options would be reflected in switching operations, and the associated administrative impacts to suppliers.	Industry associations (EURELECTRIC and Eurogas) have publicly supported consumer access to neutral and reliable comparison tools. In particular, increased reliability and impartiality in comparison tools may encourage new market entrants, thereby improving the likelihood of a level playing field. However, some suppliers are unlikely to welcome measures to certify comparison tools as this may have an impact on how and where their offers are published, and their ability to tailor tariffs to different consumers (in terms of cost, etc.). Some may also lose out financially if they are no longer able to influence the ranking of search results to promote certain offers; this applies both to energy suppliers and to CT providers. Insofar as the measures lead to increased switching, this will result in increased administrative costs to suppliers.	Most suppliers are unlikely to welcome EU legislation addressing the content or format of energy bills, as this limit their ability to tailor bills to different consumers. Some may also benefit from the low awareness amongst their consumer base of information that may be contained in bills, such as switching information, consumer rights, and consumption levels.
Comparison tool providers	Not affected.	More stringent requirements in terms of reliability and impartiality may increase their costs, as may the need for accreditation. However, such costs may be offset by an increase in sales due to improved trustworthiness of the comparison tool.	Not affected.

Affected party	Measure		
	7.4. Facilitating supplier switching	**7.5. Comparison Tools**	**7.6. Improving Billing Information**
End consumers	Some end consumers would benefit from contract exit fees (permitted in the preferred option) if such fees mean that suppliers are able to offer them lower prices or better levels of service. However, all consumers are likely to benefit from a complete ban on other switching-related fees (as per the preferred option), as well as greater transparency around any switching-related fees they may be charged. More generally, the majority of consumers would benefit from further restricting the use of switching-related charges. Such charges are a financial barrier to accessing better deals, disproportionately affect decision making, foster uncertainty on the benefits of switching, and reduce retail-level competition.	The preferred option would benefit many consumers, as the offers displayed would be more representative of the best ones (e.g. those offering the best value for money and the best service levels) available on the market. Asymmetric access to information would be reduced. Consumers would have greater trust in their ability to select the best offer through improvements in levels of service, and they would be better protected. They will be better able to make informed choices, and to benefit from the internal market.	Some end consumers would benefit from contract exit fees if such fees mean that suppliers are able to offer them lower prices or better levels of service. However, all consumers are likely to benefit from a complete ban on other switching-related fees, as well as greater transparency around any switching-related fees they may be charged. More generally, the majority of consumers would benefit from further restricting the use of switching-related charges. Such charges are a financial barrier to accessing better deals, disproportionately affect decision making, foster uncertainty on the benefits of switching, and reduce retail-level competition.

Annex III: Who is affected by the initiative and how

Annex IV: Analytical models used in preparing the impact assessment.

Description of analytical models used

In order to perform the quantitative analysis for the various Problem Areas, most notably Problem Areas I and II, as well as for the evaluation of certain individual measures described in the Annexes, a number of specialized energy modelling tools were used. The selection of the modelling tool to be used in each case was made based on its ability to answer the specific questions raised in each Problem Area.

METIS

For assessing the benefits of specific market design measures and their effect to power system operation and market functioning, a new optimization software – METIS – was used, currently being developed for the Commission[16].

METIS was presented to the Member States' Energy Economists Group on April 5th 2016. The Commission will be eventually the owner of the final tool. For transparency reasons, all deliverables related to METIS, including all technical specifications documents and studies, are intended to be published on the website of DG ENER[17].

Global Description

METIS is an on-going project initiated by DG ENER for the development of an energy modelling software, with the aim to further support DG ENER’s evidence-based policy making, especially in the areas of electricity and gas. The software is developed by a consortium (Artelys, IAEW (RWTH Aachen University), ConGas, and Frontier Economics) and a first version covering the power and gas system has already been delivered to DG ENER.

It is an energy model covering with high granularity (geographical, time etc.) the whole European energy system for electricity, gas and heat. In its final version it should be able to simulate both system and markets operation for these energy carriers, on an hourly level for a whole year and under uncertainty (capturing weather variations and other stochastic events). METIS works *complementary* to long-term energy system models (like PRIMES and POTEnCIA), as it focuses on simulating a specific year in greater detail. For instance, it can provide hourly results on the impact of higher shares of intermittent renewables or additional infrastructure built, as determined by long-term energy system models.

Upon final delivery, METIS will be able to answer a large number of questions and perform highly detailed analyses of the electricity, gas and heat sectors. A number of

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16 http://ec.europa.eu/dgs/energy/tenders/doc/2014/2014s_152_272370_specifications.pdf

17 Once operational, the envisaged link is expect to be the following: https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

topics will be possible to tackle with METIS for the whole EU and/or specific regions, like:

- The impacts of mass Renewable Energy Sources integration to the energy system operation and markets functioning (for one or all sectors);
- Cost-benefit analysis of infrastructure projects, as well as impacts on security of supply;
- Studying the potential synergies between the various energy carriers (electricity, gas, heat).

On the other hand METIS is not designed to answer (at least in its first stage) questions like:

- Optimal investment planning (capacity expansion) for the EU generation or transmission infrastructure;
- Impacts of measures on network tariffs and retail markets;
- Short-term system security problems for the electricity and gas system (requiring a precise estimation of the state of the network and potential stability issues);
- Flow-based market coupling and measures on the redesign of bidding areas;
- Any type of projection for the energy system.

Description of the Power Markets and System Models

The software replicates in detail market participant's decision processes, as well as the operation of the power system. For each day of the studied year, all market time frames are modelled in detail: day-ahead, intraday, balancing. Moreover METIS also simulates the sizing and procurement of balancing reserves, as well as imbalances.

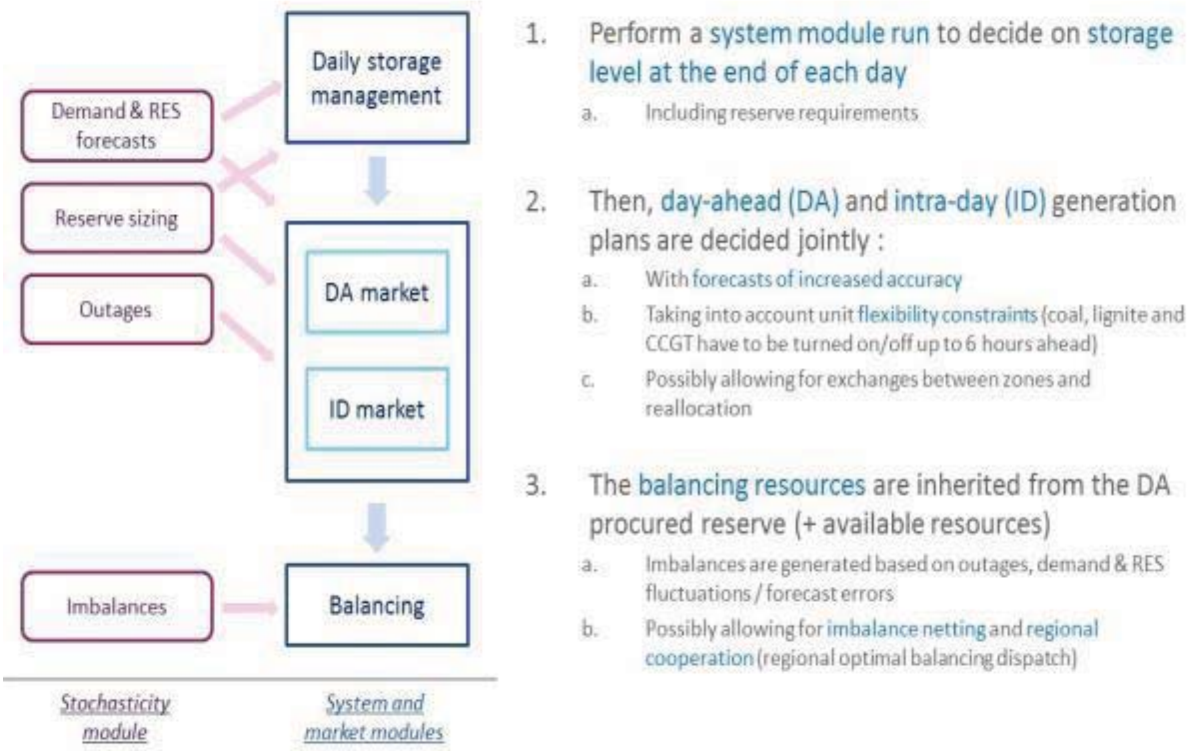
Uncertainties regarding demand and RES E power generation are captured thanks to weather scenarios taking the form of hourly time series of wind, irradiance and temperature, which influence demand (through a thermal gradient), as well as PV and wind generation. The historical spatial and temporal correlation between temperature, wind and irradiance are preserved.

Calibrated Scenarios – METIS has already been calibrated to a number of scenarios of ENTSO-E's Ten-Year Network Development Plan ('TYNDP') and PRIMES. METIS versions of PRIMES scenarios include refinements on the time resolution (hourly) and unit representation (explicit modelling of reserve supply at cluster and Member State level). Data provided by the PRIMES scenarios include: demand at Member State-level, primary energy costs, CO_2 costs, installed capacities at Member State-level and interconnection capacities.

Geographical scope – In addition to EU Member States, METIS scenarios incorporate ENTSO-E countries outside of the EU (Switzerland, Bosnia, Serbia, Macedonia, Montenegro and Norway) to model the impact of power imports and exports to the EU power markets and system.

Market models –METIS market module replicates the market participants' decision process. For each day of the studied year, the generation plan (including both energy generation and balancing reserve supply) is first optimized based on day-ahead demand and RES E generation forecasts. Market coupling is modeled via NTC constraints for interconnectors. Then, the generation plan is updated during the day, taking into account updated forecasts and asset technical constraints. Finally, imbalances are drawn to simulate balancing energy procurement.

Figure 1: Simulations follow day-ahead to real-time market decision process



Source: METIS

Reserve product definition – METIS simulates FCR, aFRR and mFRR reserves. The product characteristics for each reserve (activation time, separation between upward and downward offers, list of assets able to participate, etc.) are inputs to the model.

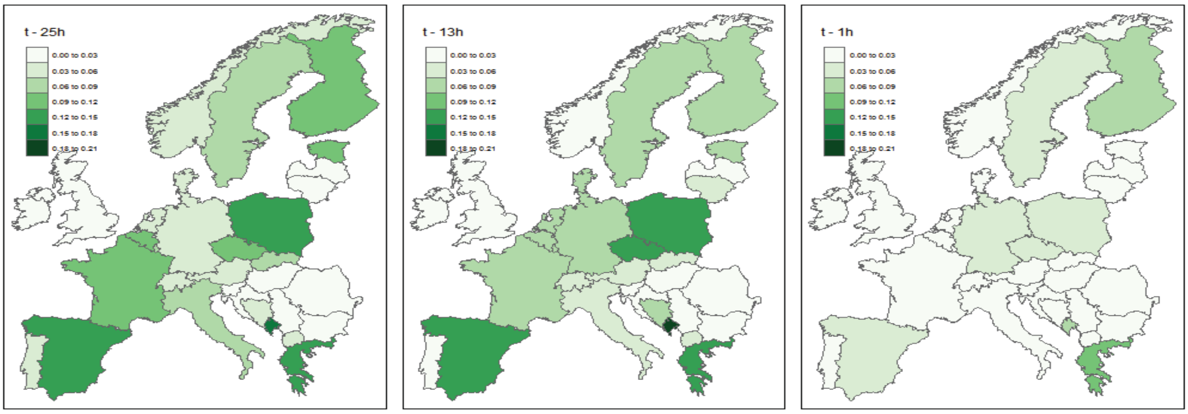
Reserve dimensioning – The amount of reserves (FCR, aFRR, mFRR) that has to be secured by TSOs can be either defined by METIS users or be computed by METIS stochasticity module. The stochasticity module can assess the required level of reserves that would ensure enough balancing resources are available under a given probability. Hence, METIS stochasticity module can take into account the statistical cancellation of imbalances between Member States and the potential benefits of regional cooperation for reserve dimensioning.

Balancing reserve procurement – Different market design options can also be compared by the geographical area in which TSOs may procure the balancing reserves they require. METIS has been designed so as to be able to constrain the list of power plants being able to participate to the procurement of reserves according to their location. The different options will be translated in different geographical areas in which reserves have to be procured (national or regional level). Moreover, METIS users can choose whether demand response and renewable energy are allowed to provide balancing services.

Balancing energy procurement – The procurement of balancing energy is optimized following the same principles as described previously. In particular, METIS can be configured to ban given types of assets, to select balancing energy products at national level, to share unused balancing products with other Member States, or to optimize balancing merit order at a regional level.

Imbalances – Imbalances are the result of events that could not have been predicted before gate closure. METIS includes a stochasticity module which simulates power plant outages, demand and RES E generation forecast errors from day-ahead to one hour ahead. This module uses a detailed database of historical weather forecast errors (for 10 years at hourly and sub-national granularity), provided by the European Centre for Medium-Range Weather Forecasts ('ECMWF'), to capture the correlation between Member State forecast errors and consequently to assess the possible benefits of imbalance netting. The stochasticity module will be further extended in the coming year to include generation of random errors picked from various probability distributions either set by the user or based on historical data.

Figure 2: Example of wind power forecast errors for a given hour of the 10 years of data.



Source: METIS

PRIMES suite of models

In order to assess the impacts of the various market design options on generator profits and investments, as well as the impact of capacity remuneration mechanisms and their different designs, a suite of models built by NTUA were used, with PRIMES model being at its core.

PRIMES

PRIMES[18] is a partial-equilibirum model of the energy system. It has been used extensively by the European Commission for settting the EU 2020 targets, the Low Carbon Economy and the Energy 2050 Roadmaps, as well as the 2030 policy framework for climate and energy.

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18 http://ec.europa.eu/clima/policies/strategies/analysis/models/docs/primes_model_2013-2014_en.pdf.

PRIMES is a private model which has been developed and is maintained by E3MLab/ICCS of National Technical University of Athens[19] in the context of a series of research programmes co-financed by the European Commission. The model has been peer reviewed successfully, most recently in 2011[20].

The PRIMES model is suitable for analysing the impacts of different sets of climate, energy and transport policies on the energy system as a whole, notably on the fuel mix, CO2 emissions, investment needs and energy purchases as well as overall system costs. It is also suitable for analysing the interaction of policies on combating climate change, promotion of energy efficiency and renewable energies. Through the formalised linkages with GAINS non-CO_2 emission results and cost curves, it also covers total GHG emissions and total non-ETS sector emissions. It provides details on the Member State level, showing differential impacts across Member States.

Decision making behaviour is forward looking and grounded in micro-economic theory. The model also represents in explicit way energy demand, supply and emission abatement technologies, and includes technology vintages. The core model is complemented by a set of sub-modules modelling specific sectors. The model proceeds in five year steps and has been calibrated to Eurostat data for the years 2000 to 2010.

For the electricity sector, the PRIMES model quantifies projection of capacity expansion and power plant operation in detail by Member State distinguishing power plant types according to the technology type (more than 100 different technologies). The plants are further categorised in utility plants (plants with as main purpose to generate electricity for commercial supply) and in industrial plants (plants with as main purpose to cogenerate electricity and steam or heat, or for supporting industrial processes). The model finds optimal power flows, unit commitment and capacity expansion as a result of an inter-temporal non-linear optimisation; non-linear cost supply functions are assumed for all resources used by power plants for operation and investment, including for fuel prices (relating fuel prices non-linearly with available supply volumes) and for plant development sites (relating site-specific costs non-linearly with potential sites by Member State); the non-linear cost-potential relationships are relevant for RES E power possibilities but also for nuclear and CCS.

The simulation of plant dispatching considers typical load profile days and system reliability constraints such as ramping and capacity reserve requirements. Flow-based optimisation across interconnections is simulated by considering a system with a single bus by country and with linearized DC interconnections. Capacity expansion decisions depend on inter-temporal system-wide economics assuming no uncertainties and perfect foresight.

The optimisation of system expansion and operation and the balancing of demand and supply are performed simultaneously across the EU internal market assuming flow-based allocation of interconnecting capacities. The outcome of the optimisation is influenced by policy interventions and constraints, such as the carbon prices (which vary endogenously

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19 http://www.e3mlab.National Technical University of Athens.gr/e3mlab/.
20 https://ec.europa.eu/energy/sites/ener/files/documents/sec_2011_1569_2.pdf'.

to meet the ETS allowances cap), the RES E feed-in tariffs and other RES E obligations, the constraints imposed by legislation such as the large combustion plant directive, constraints on the application of CCS technologies, policies in regard to nuclear phase-out, etc.

The optimality simulated by the model can be characterised either by a market regime of perfect competition with recovery of stranded costs allowed by regulation or as the outcome of a situation of perfectly regulated vertically integrated generation and energy supplying monopoly. This is equivalent of operating in a perfect way a mandatory wholesale market with marginal cost bidding just to obtain optimal unit commitment and a perfect bilateral market of contracts for differences for power supply through which generators recover the capital costs.

According to the model-based simulations, the capital costs of all plants, taken all together as if they belonged to a portfolio of a single generating and supplying company, are exactly recovered from revenues based on tariffs applied to the various customer types. This result does not guarantee that the optimal capacity expansion fleet suggested by the model-based projections cam be delivered in the context of more realistic market conditions with fragmentation and imperfections.

PRIMES was not directly used in this impact assessment, although the PRIMES EUCO27 setup was the basis for all analyses, with all inputs exogenous to the power sector, as well as generation capacities, coming from it. The main obstacle in using PRIMES for this impact assessment was that it assumes a perfectly competitive and well-functioning market.

For this scope two sub-modules closely linked to PRIMES were used instead:

- PRIMES/IEM is a day-ahead and unit commitment simulator, modelling the operation of the European electricity markets and system for a given year, being able to capture different market designs and market participant behaviours.
- PRIMES/OM is a variant of PRIMES, modifying the use of PRIMES in order to simulate investments under various competition regimes and with the possibility to capture the effect of CMs.

The two models are described below in more detail[21].

PRIMES / IEM

PRIMES/IEM aims at simulating in detail the sequence of power markets - Day-ahead, Intraday, Balancing and Reserve Procurement - in the EU for one year, covering all EU 28 Member States and their interconnections (also linked to non-EU European countries).

PRIMES/IEM is calibrated to PRIMES projections, taking as exogenous inputs:

[21] The detailed methodology followed, along with results, is described in a relevant report prepared for the scope of the impact assessment: "*Methodology and results of modelling the EU electricity market using the PRIMES/IEM and PRIMES/OM models", NTUA (2016)*

- Load (hourly);
- Power plant capacities (as projected) and their technical-economic characteristics, including old plants as available in projection period, new investments and refurbishments as projected by PRIMES;
- Fuel prices, ETS carbon prices, taxes, etc.;
- Resource availability for intermittent renewables;
- Interconnection capacities;
- Heat or Steam serving obligations of CHP plants having production of heat or steam as main purpose;
- Restrictions derived from policies, e.g. operation restrictions on old plants, renewable production obligations, if applicable, support schemes of renewables, biomass and CHP.

PRIMES/IEM disaggregates the interconnection network, considering more than one node per country, with connecting grids within the countries, in order to represent intra-country grid congestions. The assumptions about the grid within each country and across the countries change over time, reflecting an exogenously assumed grid investment plan. It also uses a more disaggregated hourly resolution than PRIMES, in representing load and availability of intermittent RES E resources, as well as more disaggregated technical and economic data for each plant than PRIMES, to represent cyclical operation of plants, possible shut-downs and start-ups. Finally, PRIMES-IEM uses detailed data on ancillary services (reserves) and the capability of plants to offer balancing services.

The day-ahead algorithm (GAMS program, written by E3MLab) is based on the EUPHEMIA[22] algorithm. The code runs for all countries and the user can select countries to simulate market coupling. The power plant capacities, demand (hourly for the days selected) and other information (e.g. grid) come from PRIMES database and projections. The linkage of data to PRIMES is fully automatic. The user can define rules for bidding by the plants, and the power plants (production hourly) which are 'must-take' and/or nominations. Available transfer capacities between countries can also be specified in the interface.

The unit commitment algorithm (GAMS program written by E3MLAB and solved as a mixed integer linear program) is a fully detailed plant operation scheduling algorithm. It includes the technical features of the power plants (technical minimum, minimum up-time, minimum down-time, ramp-up rates, ramp-down rates, time to synchronize, time to shut down and capability of providing ancillary reserve services to the system), the technical features of the interconnectors (applying DC linear power flows) and the reserve requirements of the system (primary, secondary, spinning tertiary, non-spinning tertiary and optionally ramping-flexibility reserves). The program runs simultaneously for the selected countries, which are assumed to operate under a coordinated-synchronized unit commitment. The program runs on an hourly basis and simultaneously for the sequence of typical days; runs fully one day having assumed next day, and so on.

[22] EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm) is the single price coupling algorithm used by the coupled European PXs (http://energy.n-side.com/day-ahead/).

The code is fully consistent with the unit commitment codes ran by TSOs in Europe and in the USA (compatible with the recommended code by FERC in the USA).

The day-ahead market Simulator (DAM_Simul) runs all EU countries simultaneously, solving market clearing by node (one node per country) and calculating interconnection flows restricted by DC power flows and by Available Transfer Capacities (defined by pair of countries).

Market participant bidding[23] is based on marginal costs plus mark-up reflecting scarcity. Must take CHP, RES and nominated capacities are included in DAM simulation as fixed (unchanged) hourly amounts. Similarly the reservation of cross-border capacity for nominations is fixed. In some policy-options these assumptions are relaxed. The wholesale prices of DAM are calculated from the relaxed problem, after having run the mixed integer problem. The DAM-Simulator runs pan-European and includes interconnection flows subject to limitations of power flow and NTC/ATC restrictions as applicable and if applicable in each policy option.

The unit commitment simulator (UC_Simul) includes exogenously defined reserve requirements, the outcomes of the event generator, the operation schedule of all units, the bids in DAM and penalty factors for slack variables (re-dispatching). Operation of small-RES E and must-take CHP is fixed. The unit commitment simulator runs pan-European limited by power flows and NTC values.The purpose of this run is to determine the deviations from DAM schedule, to be used in the intraday and balancing simulator.

The Intraday and Balancing Simulator (IDB_Simul) runs the above intraday and balancing market (once for 24-hours all together) and determines a price for deviations, the financial settlement of deviations and a revised schedule for operation of units and interconnectors.

In IDB_Simul, eligible resources can bid for supplying power to meet the deviations. The bids can differ for upward and for downward changes of power supplied by the eligible resources. Eligibility is defined specifically for each policy option. Capacity from interconnectors may be eligible but only if remaining capacities (beyond the schedule of the unit commitment) allow for this.

[23] Bidding functions are defined by plant in DAM on the basis of the marginal fuel cost of the plant, increased by a mark-up defined hourly as depending on scarcity. The modelling of the bidding behavior of generators, similar in PRIMES/IEM and PRIMES/OM, is discussed in detail in the PRIMES/OM Section.

Figure 3: Modelling Sequence in PRIMES/IEM

Sequence of modelling of one day

1. Day-Ahead Market Simulation (DAM_Simul)
    - Plant operation schedule (DAM)
    - Financial settlement
2. Random Events Generator (REG)
    - Wind, Solar, demand, outages of plants and/or interconnections
3. Unit Commitment Simulator (UC_Simul)
    - Reserve requirements exogenous
    - Revised plant operation schedule (UCS)
    - Deviations of UCS from DAM
4. Intra-Day and Balancing Simulator (IDB_Simul)
    - Demand for deviations
    - Supply (eligible resources) and their bidding
    - Financial settlement
    - Revised plant availability
5. Reserve and ancillary services market and procurement Simulator (RAS_Simul)
    - Demand for reserves and ancillary services
    - Supply (eligible resources) and their bidding
    - Financial settlement
    - Revised plant availability
6. Unit Commitment Simulator (physical)
    - Plant operation
    - Plant costs
    - Emissions and fuel consumption

Source: PRIMES/IEM

In the Reserve and ancillary services procurement Simulator (RAS-Simul) demand for reserves is defined exogenously (equal to demand used in the UC_Simul). The outcome of RAS-Simul is the remuneration of the resources for providing reserves and a possible (small) modification of the schedule of units and interconnection flows.

For each policy option the demand for reserves is differentiated. Eligible resources can bid for supplying power to meet the demand for the different types of frequency reserves. Also, a subset of plants are eligible in each market for reserve. When the bids are endogenous and market-based, the prices include scarcity markups, with scarcity referring to the market for reserves. Eligibility of resources is defined differently for each policy option. Resources available cross-border can participate (differently constrained by policy option) in the markets for reserves subject to limitation from availability of interconnection capacity, which is the capacity remaining after the schedule of the unit commitment and intraday. Resources not scheduled after the unit commitment and the intraday can submit bids to the markets for reserves (only for tertiary reserve) but only gas turbines are eligible for this purpose.

For the finalisation of the simulation, the unit commitment simulator is run again assuming as given the schedule of units and interconnection flows resulted from previous steps and the load (hourly). The objective function includes only penalties for deviation from the schedule resulted from the previous step. The ascending order of penalties is RES E, interconnection flows, gas, solids, nuclear, demand or another order defined specifically by policy option. If must-take CHP and small-RES E can be curtailed then they are also included with penalties, otherwise they are fixed. The unit commitment simulator runs at this stage pan-European and applies flow based allocation of interconnections. The purpose of this run is to calculate the production by plant, consumption of fuel, operation cost by plant and emissions.

Demand response is modelled similarly to pumping transferring power from peak- to baseload; the amount of energy reduced in peak hours is compensated in the same day by additional energy consumption in other time segments, chosen endogenously. Therefore demand response bids for differential demand reduction and demand increase at different times, the bidding price reflecting costs (exhibiting decreasing return to scale), scarcity cost opportunity and the bidding quantity being subject to potential. Demand response (defined differently for each policy option) can be incorporated in all stages, i.e. DAM, intraday, reserves.

The simulation cycle closes by the reporting of financial balances (load payments, revenues and costs) for each generator, load and the TSO and calculating unit cost indicators (e.g. for reserves, etc.). As the simulation is stochastic, the expected values of the outcomes are calculated as the average of results by case of random events weighted by the frequency of the case.

PRIMES / OM

PRIMES/OM is a modified version of the power sector model of PRIMES, tailored to the needs of the impact assessment. It uses the PRIMES database, as well as its scenario assumptions. By departing from the usual perfect competition assumption of PRIMES, it can simulate investment behavior and the influence of CMs under various competition regimes and bidding behaviours. Simulations are dynamic, demand is price elastic and cross-border flows endogenous.

The model variant covers the power sector of all EU Member States linked together. The model simulates an organized wholesale market, calculating prices, revenues and costs, and estimating the probability of eventual mothballing of old plants and the cancelling (partially or entirely) of investment in new plants as a consequence of the revenues associated to the individual plant.

The model includes as an option a stylized CM auction, with or without cross-border participation, which is general in scope in terms of eligibility and covers all dispatchable generators. The inclusion or not of national CMs varies by scenario simulated. The model considers that the presence of a CM leads to lower risk premium factors which are used by generators to decide mothballing of old plants or cancelling of investments. However, the CM demand functions, as specified according to the logic of the model, are such that they may grant unnecessarily capacity payment to some plant categories.

Figure 4: Modelling Sequence in PRIMES/OM

291 Annex IV: Analytical models used in preparing the impact assessment.

Sequence of investment modelling in PRIMES/OM

1. Define Context
   - Bidding Behavior (e.g. marginal cost, scarcity pricing)
   - Policy Scenario (in terms of GHG, ETS, RES Targets)
2. Starting point for investment is the most relevant PRIMES scenario
3. Simulate market operation under assumed generating capacities and bidding behavior
   - Day ahead market
   - Unit Commitment
4. In case CMs are assessed, include:
   - Design details of CM
   - Cross border specifications
5. Derive value of investment
   - Calculate degree of recovery of fixed costs
   - Derive Risk
6. Modify investment behavior
   - Based on real option theory
   - If CM are assessed, they are assumed to influence the risk
7. Repeat the sequence until convergence

Source: PRIMES/OM

The model runs dynamically from 2020 until 2050, in 5-year steps. It uses a full PRIMES model scenario as starting point, from where it takes the first input for load, renewables and the projection of power plant capacities. Subsequently it modifies load based on demand response, capacity availability and investment (except for renewables, industrial and district heating CHP) as a result of the mechanism described above.

A fundamental assumption of the oligopoly model is that the economics on which capacity-related decisions are made by generators are specified individually for each plant. However, the standard PRIMES model looks at the economics of portfolios of plants to determine the outcome of capacity-related decisions. It also, enables us to quantify the differences between market outcomes in perfect competition, where marginal cost bidding is applied, and under the oligopoly market structure where uplift is applied to the bids of market participants.

Main characteristics of PRIMES/OM

Investment Evaluation – A stochastic analysis is performed with respect to the main uncertainty factors affecting investments or early retirement of old plants, thus introducing a probability space for the simulation of investment decision under uncertainty. These factors have been identified as follows: (a) ETS carbon prices, (b) natural gas prices in relation to coal prices, and (c) the volume of demand for electricity net of renewables. In addition to the uncertainties pertaining to the framework conditions, the heterogeneity of decision makers in the investment evaluation process has also been taken into account. This is accomplished by considering a distribution probability of the hurdle rates that an investor considers (subjectively) for undertaking an investment. The hurdle rates are equivalent to the minimum Internal Rate of Return value for deciding positively upon an investment. The frequency distribution is modified in terms of mean and standard deviation dependent upon the certainty or lack thereof of revenues;

revenues coming from the energy only market compared to those coming from a CM imply higher mean and standard deviation of the distribution of hurdle rates.

Combining all of the above, a sample of about 100 combinations is generated around the EUCO27 trajectory for the three stochastic factors for the whole time period (as vectors over time) and 100 hurdle rate cases with combined probabilities. For the purposes of investment evaluation, the pan-EU energy-only market is run for each sample of the stochastic factors and revenues and costs for each plant are calculated for their total lifetime, including possible extension of operation. Two sources of revenues are accounted for: from operation in the energy-only market and from supplying reserve to the system. For the cost calculation, capital annuity payments were excluded. Using the revenues and costs calculated as such, the economic performance of each power plant is found, defined as the present value of future earnings above operation costs for each sample of uncertain factors and each hurdle rate case. The expected economic performance of a plant is the result of an average of performances weighted by the probabilities.

Heterogeneous decision makers, identified by the distribution of the hurdle rates as mentioned above, have a different threshold probability in order to decide whether or not to continue operating a plant or cancelling investment. In other words, there is an association of expected economic performance of each plant, as represented by its present value, with investment cost of new plants or with salvage value (remaining capital value) for plants, which are distributed across the decision makers according to a normal probability distribution function. Therefore, the frequency of decision about survival of a plant's capacity as a function of the economic performance indicator is used as the probability of survival. The capacity volume of the plant as projected by PRIMES in the context of the EUCO27 scenario multiplied by the probability of survival provides us with an update of the capacity volume.

Modelling of CMs – When a CM is assumed to be in place, it is modelled in a stylized manner. All capacities are eligible, if dispatchable, including hydro lakes and storage, provided that they are not under a different support scheme. For example, CHP, biomass, etc. are excluded. Also, plants in the process of decommissioning or operating few hours per year due to environmental restrictions as projected in PRIMES are excluded. All capacities are remunerated for the available capacity excluding outages.

The CM payment is a result of an auction. The CM price is derived from the intersection of demand for capacity and the offers, sorted in ascending price order. Demand for capacity is defined as a negative-sloped linear line depending upon a price cap and linking two capacity points: the minimum and maximum requirements. For all capacity offered up to the minimum requirement the auction clearing price is equal to the price cap, while for the maximum requirement it is equal to zero. The definition of the demand curve takes into account trusted imports at peak load times and the guaranteed proportion of exports. Therefore, implicit participation of flows over interconnections is taken into account. Cross-border participation, when applicable, increases capacity offering. Removal of capacities (due to mothballing or cancelling of investment, or because the capacity is offered to a foreign CM) also decreases capacity offering. The CM winners sign a reliability option (one way option) which has a strike price. If the wholesale market price is above the strike price they are assumed to return the revenues above strike price. The results of the CM auctions, namely the stream of revenues they provide to generators, are taken into account by the oligopoly model in the final step of investment evaluation.

Bidding Behaviour - The model assumes a scarcity bidding function as a means to mimic the strategic behaviour of market players in an oligopoly. The bidding function is specific to each individual plant and it takes into account hourly demand, plant technology and plant fixed costs in order to evaluate the hourly bid price of each generator.

In order to model the bidding behaviour of plants, they are assigned to one of four different types of merit order: no-merit, baseload, mid-load, and peak load. Hydro-reservoirs consider also water availability. The assignment of plants takes place based on their technology as well as on whether they participate in the energy only market; non-dispatchable generators are considered as must-take, and therefore are assumed to bid at zero price. The no-merit order type is intended to include this type of plants. The baseload category includes mainly nuclear and coal/lignite plants, the mid-load CCGTs, and the peak load of GTs and Reservoir Hydro.

Subsequently, the capacities of all plants within a merit order type are summed up in order to determine the total capacity of every type, developing a merit stack. Then the hourly demand is compared with the merit stack in order to estimate for every hour which merit order type is expected to be on the margin. This is the type on which a scarcity mark-up will be applied, assuming this is the market segment in which all strategic behaviour of market participants takes place for a specific hour. The marginal cost which sets the basis for the price at which each plant offers its energy is calculated based on variable cost data from the PRIMES database. The mark-up is calculated based on the following equation:

$$SB_p = MC_p + CEIL_m * \mathrm{e}^{-\mathbf{RATE}_p \cdot \left[\frac{\mathbf{SUPP}_m}{\mathbf{DEMD}_m} - 1\right]}$$

P is the plant identifier, M the merit order type, MC the Marginal cost, $SUPP$ the total supply (capacity) of merit order type, $DEMD$ the hourly demand specific to merit order type, $CEIL$ the price ceiling for merit order type, $RATE$ the (inverse) rate of mark-up and SB the scarcity bid. The demand specific to a generation type is calculated as the residual of hourly demand minus the capacity of the merit order types which lie below the marginal.

The price ceiling is specific to every merit order type and is applied in order to guarantee that the merit order is never reversed, i.e. peak load plants being dispatched before mid-load plants, mid-load before baseload, etc. Also, the rate specific to each plant is dependent upon the fixed costs of the plant, which comprise mainly of capital costs, in a risk averse manner. This convention is in place so that plants with high fixed costs are more reluctant to apply a mark-up to their marginal cost in fear of staying out-of-merit and not being dispatched due to the mark-up being too high. Finally, if in post-calculation the scarcity bid exceeds the price ceiling, it is set equal to the ceiling.

Description of methodological approach followed concerning baseline

PRIMES EU Reference Scenario 2016

A common starting point to all Impact Assessments is the EU Reference Scenario 2016 ('REF2016'). It projects greenhouse gas emissions, transport and energy trends up to 2050 on the basis of existing adopted policies at national and EU level and the most recent market trends. This scenario was prepared by the European Commission services in consultation with Member States. All other PRIMES scenarios build on results and modelling approach of the REF2016.

Although REF2016 presents a comprehensive overview of the expected developments of the EU energy system on the basis of the current EU and national policies, and could be considered as the natural baseline for all impact assessments, it fails doing so for an important reason. This scenario does not have in place the policies to achieve the 2030 climate and energy targets that are already agreed by Member States in the European Council Conclusions of October 2014. It also does not reflect the European Parliament's position on these targets.

Therefore, although it was important for all initiatives to have a common "context" in order to ensure coherent assessments, each Impact Assessment required the preparation of a specific baseline scenario, which would help assess specific policy options relevant for the given Impact Assessment.

Central Policy Scenario: PRIMES EUCO27

Because of the need to take into account the minimum agreed 2030 climate and energy targets (and the 2050 EU's decarbonisation objectives) when assessing policy options for delivery of these targets, a central policy scenario was modelled ('EUCO27').

This scenario is the common policy scenario for all Impact Assessments. Additional baseline and policy scenarios were prepared for each Impact Assessment, addressing the specific issues to be assessed by each initiative, notably which measures or arrangements have to be put in place to reach the 2030 targets, how to overcome market imperfections and uncoordinated action of Member States, etc. A summary of the approach followed in each respective impact assessment can be found in the Annex IV of the RED II impact assessment.

This approach of separating a central policy scenario reaching the 2030 targets in a cost-effective manner and other scenarios that look into specific issues related to implementation of cost effective policies enables to focus on "one issue at a time" in the respective separate analysis. It enabled to assess in a manageable manner the impacts of several policy options and provide elements of answers to problem definitions listed in the 2016 impact assessment, without the need to consider the numerous possible combinations of all the options proposed under each respective initiative.

PRIMES EUCO27 scenario is based on the European Council conclusions of October 2014[24]. In particular, the following were agreed among the heads of states and governments:

- Substantial progress has been made towards the attainment of the EU targets for greenhouse gas emission reduction, renewable energy and energy efficiency, which need to be fully met by 2020;
- Binding EU target is set of an at least 40% domestic reduction in greenhouse gas emissions by 2030 compared to 1990;
- This overall target will be delivered collectively by the EU in the most cost-effective manner possible, with the reductions in the ETS and non-ETS sectors amounting to 43% and 30% by 2030 compared to 2005, respectively;

[24] http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/145397.pdf.

- A well-functioning, reformed ETS with an instrument to stabilise the market in line with the Commission proposal will be the main European instrument to achieve this target; the annual factor to reduce the cap on the maximum permitted emissions will be changed from 1.74% to 2.2% from 2021 onwards;
- An EU target of at least 27% is set for the share of renewable energy consumed in the EU in 2030. This target will be binding at EU level;
- An indicative target at the EU level of at least 27% is set for improving energy efficiency in 2030 compared to projections of future energy consumption based on the current criteria. It will be delivered in a cost-effective manner and it will fully respect the effectiveness of the ETS-system in contributing to the overall climate goals. This target will be reviewed by 2020, having in mind an EU level of 30%;
- Reliable and transparent governance system is to be established to help ensure that the EU meets its energy policy goals, with the necessary flexibility for Member States and fully respecting their freedom to determine their energy mix;

The above requirements, with a minimum energy saving level of 27%, are reflected in EUCO27. Concrete specifications on assumptions were made by the Commission in order to reach the relevant targets by using a mix of concrete and yet unspecified policies. A detailed description of the construction of this scenario is presented in Section 4 of the EE impact assessment and its Annex IV.

As this scenario is not directly used in the present impact assessment, the reader is referred to the relevant technical annexes of the EE and RED II impact assessments for more details on its main assumptions and results. Table 1 below presents the main projections for 2030 related to the power system for EU28.

Table 1: PRIMES EUCO27 Modelling Results for the power system (EU28)

	2000	2015	2030	Share in total for 2030 (%)	% diff 2015-2010	% diff 2030-2015
Electricity consumption (in TWh)	**3,029.0**	**3,271.8**	**3,525.6**		8%	8%
Final energy demand	2,530.7	2,802.4	3,081.3		11%	10%
Industry	1,061.1	1,001.4	1,054.8	30%	-6%	5%
Households	713.8	833.6	899.7	26%	17%	8%
Tertiary	683.5	899.3	982.2	28%	32%	9%
Transport	72.3	68.2	144.6	4%	-6%	112%
Energy branch	281.7	262.6	231.2	7%	-7%	-12%
Transmission and distribution losses	216.2	206.7	213.1	6%	-4%	3%
Net Installed Power Capacity (in GW_e)	**683.5**	**965.6**	**1,131.0**		41%	17%
Nuclear energy	139.6	120.8	109.9	*10%*	-13%	-9%
Renewable energy	129.0	366.7	652.2	*58%*	184%	78%
Hydro (pumping excluded)	115.8	127.5	133.3	12%	10%	5%
Wind on-shore	12.7	130.6	246.1	22%	-	88%
Wind off-shore	0.1	11.0	37.9	3%	-	246%
Solar	0.2	97.4	233.8	21%	-	140%
Biomass-waste fired	12.7	27.9	53.1	5%	121%	90%
Other renewables	0.8	1.1	2.1	0%	32%	86%
Thermal power	414.9	478.1	368.9	*33%*	15%	-23%
Solids fired	194.5	176.6	99.4	9%	-9%	-44%
Oil fired	83.3	53.1	15.3	1%	-36%	-71%
Gas fired	123.8	219.6	200.1	18%	77%	-9%
Net Electricity generation by plant type (in TWh)	**2,844.0**	**3,090.0**	**3,396.7**		9%	10%
Nuclear energy	893.9	825.7	738.4	*22%*	-8%	-11%
Renewable energy	374.5	736.2	1,372.8	*40%*	97%	86%
Hydro (pumping excluded)	351.6	357.7	375.1	11%	2%	5%
Wind on-shore	22.2	241.4	564.4	17%	-	134%
Wind off-shore	-	32.8	127.3	4%	-	288%
Solar	0.1	103.8	303.6	9%	-	193%
Biomass-waste fired	42.9	130.6	238.1	7%	204%	82%
Other renewables	5.0	7.1	9.7	0%	42%	37%
Thermal power	1,575.6	1,528.0	1,285.6	*38%*	-3%	-16%
Solids fired	866.3	780.3	448.6	13%	-10%	-43%
Oil fired	178.4	30.2	14.6	0%	-83%	-52%
Gas fired	483.4	580.4	576.8	17%	20%	-1%

Source: PRIMES

Baseline: Current Market Arrangements ('CMA')

The Market Design Initiative addresses four different Problem Areas. The first two, addressing market functioning and investments, share a common baseline which is highly dependent on the context (e.g. based on REF2016 or EUCO27). The other two Problem Areas, concerning risk preparedness and retail markets, are more independent of the overall context, as in each case the envisaged baseline and options can apply in either context (moreover the assessment tends to be mainly qualitative). Therefore the discussion on the baseline is meaningful mainly for the first two Problem Areas.

Similar to the other 2016 Energy Union initiatives, EUCO27 was chosen as the starting point (i.e. context) of the baseline for the Market Design Initiative (so-called "Current Market Arrangements" – CMA). The EUCO27 scenario is the most relevant to the objectives of the initiative, as it provides information on the investments needed and the power generation mix in a scenario in line with the EU's 2030 objectives.

As all analysis focuses on the power sector, all assumptions exogenous to the power sector were taken from the EUCO27 scenario. This also applied for the energy mix, the power generation capacities for each period, the fuel and carbon prices, electricity demand, technology costs etc. The main obstacle in further using the EUCO27 as a baseline for this impact assessment was that it assumes a perfectly competitive and well-functioning European electricity market, more matching the end point than the starting point of the analysis. Therefore CMA differs from the EUCO27 scenario by including existing market distortions, as well as current practices and policies on national and EU level.

The CMA assumes implementation of the Network Codes, including the CACM and the EB Guidelines (the later in their proposed form). It is assumed that the CACM Guideline will bring a certain degree of harmonisation of cross-border intraday markets, gate closure times and products for the intraday, as well as a market clearing. National intraday and balancing markets will be created across EU and a certain degree of market-coupling of intraday markets will be achieved. At the same time, the EB Guideline is expected to bring certain improvements to the balancing market, namely the common merit order list for activation of balancing energy, the standardisation of balancing products and the harmonisation of the pricing methodology for balancing. Nonetheless, other important areas like harmonisation of intraday markets and balancing reserve procurement rules will not be affected by the guidelines.

The baseline does not consider explicitly any type of existing support schemes for power generation plants, neither in the form of RES E subsidies nor in the form of CMs[25]. This is governed to a large degree from the 2014 EEAG applicable as of 1 July 2014. Aid schemes existing at that moment have to be amended in order to bring them into line with EEAG no later than 1 January 2016. This with the exception of schemes concerning operating aid in support of energy from renewable sources and cogeneration that only need to be adapted to the EEAG when Member States prolong their existing schemes, have to re-notify them after expiry of the 10 years-period or after expiry of the validity of the Commission decision or change them. This implies that all existing schemes will expire by 2024 at the latest and will be adapted to the EEAG, applicable at the time of their notification. Current guidelines allows operational aid only as feed-in premium, not attributed for the hours with negative prices and with its level determined via tenders. In essence this means that non-market based support schemes are fully phased out by 2024 assuming that the rules as regards RES E and CHP aid schemes well remain unaltered when the EEAG is reviewed in 2020.

[25] Admittedly this assumption is strong, but necessary to simplify the analysis. Otherwise a riskier (for the analysis) assumption would need to be made on the future share, type and level of support for the various support schemes per Member States in the end becoming a major driver for the results and complicating their interpretation.

Moreover, the RED II proposals (part of the baseline of the present impact assessment) will enshrine and reinforce the market-based principles for the design of support schemes. As it is reasonable to assume that the RED II will enter into force prior to 2024, assuming that all support to RES E by 2030 is market based is a prudent assumption.

The effect of RES E subsidies is relevant to the MDI impact assessment only when it directly affects the merit order. Overall the cost-efficient level of investments in RES E[26] is taken as given across all assessed options, as projected in EUCO27, without examining how the costs of these investments are recuperated (topic addressed in the RED II impact assessment). The baseline assumes one of the main objectives of the RED II initiative is achieved and a framework strengthening the use of tenders as a market-based phase-out mechanism for support is in place, gradually reducing the level of subsidies over the course of the 2021-2030 period (still support schemes would exist for all non-competitive RES E technologies). Moreover it is assumed that existing FiT contracts have been phased-out by 2030 to a large degree, most importantly the ones targeted on biomass, being the ones most distorting to the merit order. As a result the assumption of not considering any non-market based support for RES E generation is reasonable and not significantly affecting the results.

As for CMs, existing or planned, they are mainly relevant for Problem Area II and did not need to appear in the common baseline of the two Problem Areas. The analysis for Problem Area I did not touch issues related to investments, thus the assumption of CMs (which would be present in all assessed options) would have a limited influence on the impacts and the ranking of the options[27]. As far as Problem Area II is concerned, again their inclusion was avoided, as any results would be highly dependent on the specific CM assumptions over the examined period. Moreover, in line with the results of the analysis in section 6.2.6.2, the effect of adding a CM would most likely be to further increase the cost of the power system. As the baseline was already a very costly scenario compared to the preferred energy-only market one, the conclusion from the comparison of the options would remain the same.

METIS calibration to EUCO27

As mentioned above, for the scope of this impact assessment METIS was calibrated to the PRIMES EUCO27 scenario. In fact, as the calibration needed to take place much before the finalisation of the PRIMES EUCO27, it was performed on one of its preliminary versions. The main elements of the calibration process, as well as the most important differences between the preliminary and the final version of EUCO27 are described below. A significantly more detailed description of the calibration has been reported on a separate document, to be found on the METIS website[28].

Preliminary EUCO27

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26 The same applies for CHP, when the main use of those plants is the production of heat/steam.

27 The CMs would not affect the merit order in problem area I, as the analysis assumes bidding based on marginal costs (not scarcity pricing, which is introduced in problem area II).

28 Once operational, the envisaged link is expect to be the following: https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

The two versions of EUCO27 are in general quite close from an EU energy system perspective. Two differences can be found in 2030, one in the RES E shares and the other in CO2 prices, slightly affecting power generation capacities and production.

RES E overall share is in both cases 27%, with a differentiation in the sectoral contribution: in the preliminary version the share of RES E is at 48.4%, while being 47.3% in the final EUCO27 version. This was mainly driven by differences in off-shore wind deployment. There is more switching from coal to gas in the final version. This is translated to 2 p.p. increase of gas in the share of power gas generation, while solids decreased by 0.5 p.p. and RES E by 1.3 p.p.. The CO_2 price, which was 38.5 EUR/tCO_2 in the preliminary version is 42 EUR/tCO_2 in the final EUCO27 version.

The effect of these differences is not very significant on the EU level, although it does have some implication on the results of specific Member States with a projected high capacity of off-shore wind in the preliminary version, e.g. the UK.

METIS calibration to PRIMES EUCO27

For the scope of this impact assessment, simulations adopted a country level spatial granularity and an hourly temporal resolution of year 2030 (8760 consecutive time-steps year), capturing also the uncertainty related to demand and RES E power generation. Modelling covered all ENTSO-E countries, not only EU Member States, as follows:

- All ENTSO-E countries for the day-ahead market;
- EU28+NO+CH for intraday, balancing and reserve procurement[29];
- EU28+NO for regional co-operation for reserve procurement, CH reserve assumed to be procured nationally.

For configuring METIS to match the (preliminary) PRIMES EUCO27 projections, a number of steps were taken, the most important of which are described in the following. Details can be found in the relevant METIS report[30].

1. The data provided for the calibration concerned only EU28. Missing data for other countries modelled with METIS (i.e. Bosnia, Switzerland, Montenegro, FYROM, Norway and Serbia) were complemented by other sources, mainly ENTSO-E 2030 vision 1 of TYNDP 2016.
2. The hourly power demand time series were based on ETNSO-E's 2030 vision 1 scenario. Data were adjusted so that on average (over 50 weather data realizations) the power demand of each country corresponds to the PRIMES EUCO27 projections.
3. Installed capacities were computed based on PRIMES EUCO27 scenario[31]. For certain EU28 countries the split between hydro lake and run-of-river of PRIMES

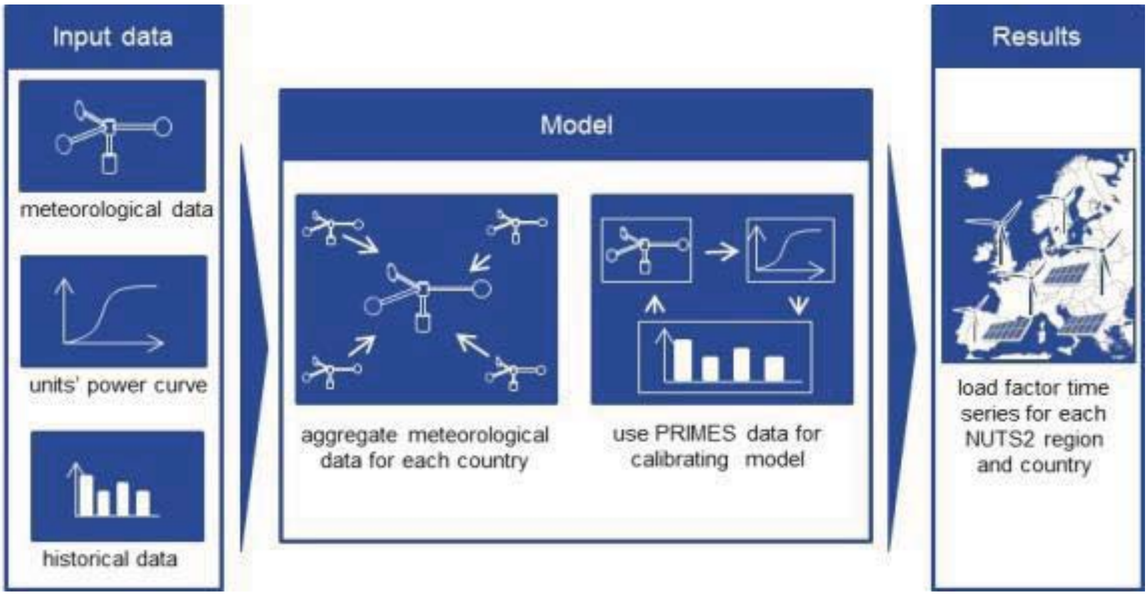
[29] Actually reserve procurement was not modelled for other non-EU28 Member States, as well as for Malta, Cyprus and Luxembourg.

[30] "*METIS Technical Note T04: Methodology for the integration of PRIMES scenarios into METIS*", Artelys (2016)

was reviewed based on historical data form ENTSO-E, due to differences in the definitions used in PRIMES (based on Eurostat) and METIS (based on ENTSO-E).

4. Generation of ten historical yearly profiles for wind and solar power was performed according to the methodology depicted in Figure 5. The methodology followed delivered annual load-factors closely matching the ones of PRIMES EUCO27.

Figure 5: PV and wind generation profiles



Source: METIS

5. Thermal plant fleets comprised of the following technologies: hard coal, lignite, CCGT, OCGT, oil, biomass. The various fleets, except oil and biomass, were divided into two or three classes (only CCGT were divided into three). Thermal installed capacities were based on PRIMES EUCO27, without though enforcing any type of constraint on the net electricity generation of these plants (which was a pure result of the modelling). The technical-economic assumptions of PRIMES were used for the power plants, complemented by other sources or databases when missing.
6. Water inflow profiles, as well as storage parameters, required important reconciliation work combing data from ENTSO-E, TSOs and PRIMES.
7. The international fuel price assumptions of PRIMES EUCO27 were used for calculating the marginal production costs of the thermal fleets. Specifically for coal and biomass, end-user fuel prices coming again from PRIMES EUCO27– including also transportation costs – were used instead.

[31] CHP units were treated as electricity-only gas plants, as currently METIS does not model the heat sector. Division of RES to small and large scale (e.g. rooftops solar) was also not captured.

8. METIS used the same NTC values as in PRIMES EUCO27[32]. NTC values between European and non-European countries are completed using ENTSO-E 2030 v1 scenario.
9. As METIS focuses in particular on the economics of security of supply, a key point is that installed capacity is consistent with peak demand. Consequently, provided OCGT capacities were optimized to satisfy security-of-supply criteria. To optimize OCGT capacities, supply-demand equilibrium was computed with "State of the art" OGCT capacities as variables over 50 years of weather data. Capacities of "oldest" OCGT fleets remain fixed to the installed capacities in 2000 which have not been replaced by 2030. Table 2 presents the results of the OCGT capacity optimization consisting in the added OCGT installed capacities per country. These additional capacities are added to the installed capacities in 2030 excluding the investment between 2000 and 2030.

Table 2: Additional OCGT capacities needed to satisfy security of supply standards

	BE	DK	FI	FR	IE	NO	SE	UK
OCGT added capacity (GW)	5	2	4	6	1	4	3	19

Source: METIS, Artelys Crystal Super Grid

METIS policy scenarios for the options of Problem Area I

This section provides information on the market design options that were modelled and assessed using METIS. Each scenario was run using the full capabilities of METIS. In fact certain aspects of METIS were further developed in order to be possible to better assess a number of the measures covered in the impact assessment.

Each scenario was intended to match the setup of one assessed option. For this purpose the options were first decomposed into a number of "fields", reflecting existing market distortions or design features that were addressed within each option. Following subsequent analysis, these fields were then narrowed down to the twelve presented in Table 3 below. For each of these fields, two or three sub-options were considered across the different scenarios. The sub-options considered (entitled "a"/""b"/"c") are identified on the right had columns of Table 3, while their description is provided in Table 4.

For all fields, sub-option "a" reflects current practices and existing market distortions, as well as the possible evolution of markets in the near future in the absence of new policies. The identification and methodology for the quantification of current practices was supported by a study performed specifically for this purpose[33].

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[32] - Regarding grid development and the interconnectors between countries, they are based on the ENTSO-E TYNDP, following the respective timelines. After the end of the TYNDP, expansions are based on known plans and the development of RES E.

[33] "*Electricity Market Functioning: Current Distortions, and How to Model their Removal*", COWI (2016).

Table 3: Overview of MDI impact assessment Problem Area I scenarios as modelled by METIS (read in conjunction with Table 4)

Action	Field	MDI options				
		0	1(a)	1(b)	1(c)	2
1	DR deployment	a	b	b	c	c
2	RES E priority dispatch	a	b	b	b	b
3	Biomass reserve procurement	a	b	b	b	b
4	Coal/lignite unit commitment at intraday	a	b	b	b	b
5	Balance responsibility	a	b	b	b	b
6	Intraday coupling	a	a	b	b	b
7	Time granularity for reserve sizing	a	a	b	b	b
8	Reserve procurement methodology	a	a	b	b	b
9	Joint/separate upward/downward reserve	a	a	b	b	b
10	Use of NTC	a	a	b	b	c
11	Reserve dimensioning and risk sharing	a	a	b	b	c
12	PV, Wind and RoR reserve procurement	a	a	a	b	b

Source: METIS

Table 4: Overview of the sub-options for each measure modelled in METIS

Measure	Topic	Description of the options
1	DR deployment	Three levels of DR deployment (sub-options a, b and c, with increasing economic potential, based on COWI BAU and PO2 scenarios[34]) were considered. In sub-option "a" DR can considered only for countries where DR has currently access to the market and only for industrial resources based on BAU potentials. In sub-option "b" DR by industrial resources appears in all countries based on BAU potentials. In sub-option "c" all DR resources participate based on the potential of the PO2 scenario, adjusted to better match EUCO27 projections and the activation limits of DR potential.
2	RES E priority dispatch	Two options were considered: a. Penalty factor for PV and Wind curtailment, priority dispatch for Biomass b. No penalty factor or priority dispatch for PV, Wind and Biomass For sub-option "a", modelling RES E priority dispatch for wind and PV was performed via a penalty factor and not by explicit priority dispatch. The reason was that there were a number of hours for certain Member States that if an explicit priority dispatch was enforced for all RES E, their power system collapsed (solution was infeasible). In reality this would most likely be addressed by the TSOs via the curtailment of RES E.
3	Biomass reserve procurement	Two options for participation of biomass in reserve procurement: a. Biomass does not participate in FCR or FRR b. Participation of Biomass (the absence of priority dispatch is a prerequisite)
4	Coal/lignite unit commitment at intraday	Two options for coal and lignite unit commitment: a. The day-ahead unit commitment decision (i.e. which plants are turned on or off) for coal and lignite power plants cannot be refined during intraday, i.e. coal and lignite plants are treated as must-runs in intraday once scheduled in day-ahead. b. Coal and Lignite can re-optimise their commitment in intraday (subject to their technical constraints).
5	Balance responsibility	By making RES E producers financially responsible for the imbalances they are encouraged to improve their generation forecasts. Two options were considered: a. H-2 forecasts were used for Wind and PV generation for reserve dimensioning and generation of imbalances. b. H-1 forecasts were used for demand and PV, while 30 min forecasts were used for Wind, leading to lower imbalances and lower reserve requirements.

[34] "*Impact Assessment support Study on downstream flexibility, demand response and smart metering*", COWI (2016)

Measure	Topic	Description of the options
6	Intraday coupling	Auctions for interconnections capacity can either be explicit, captured in METIS as if assuming the flows are fixed in H-4, or implicit, in which case flows can be updated in H-1. Two options were considered: a. Auctions were mostly explicit, except in specific areas based on current practices. b. Auctions were implicit for all interconnections. In any case, the reserve procured at day-ahead remained fixed during intraday.
7	Time granularity for reserve sizing	Two options were considered for aFRR reserve sizing: a. Fixed reserve size computed as 0.1% and 99.9% centiles of imbalance distribution over the year. While some Member States have different reserve sizes depending on demand variation, this option assumes that the reserve size is constant over the year for all Member States. b. Variable reserve size depending on the hour of the day and wind energy generation. Size is computed with 0.1% and 99.9% centiles of imbalance conditional distribution
8	Reserve procurement methodology	Reserve can be procured either day-ahead (which was modelled in METIS as a joint optimization of power and reserve hourly procurement at day-ahead) or on a fixed basis per year (in which case the mean annual value of optimal reserve procurement is used). The options were: a. Current practices b. Day-ahead procurement
9	Joint/separate upward/downward reserve	Two options were considered for upwards and downwards reserve: a. Joint procurement according to current practices b. Being two separate products which can be procured independently
10	Use of NTC	To model the process of interconnection allocation, three options were considered: a. National TSOs need to have a high security margin. For the scope of METIS, EUCO27 NTCs were reduced by 5%. b. Collaboration between TSOs reduces the need for security margins. EuCo NTC values were used. c. The introduction of a supranational entities will result in a further reduction of the security margins, leading to an increase by 5% of the EuCO NTCs.
11	Reserve dimensioning and risk sharing	To assess whether risk sharing can reduce the needs for national reserves, three options were considered. Reserve was sized using a probabilistic approach: a. At national level b. At regional level c. At EU level In order to ensure Member States can face similar security of supply risks when less reserves can be procured (Options b. and c.), part of the interconnections' capacity was reserved for mutual assistance between Member States.
12	PV, Wind and RoR reserve procurement	Two options: a. PV, Wind and Hydro RoR do not participate in FCR or FRR b. Participation of PV, Wind and Hydro RoR in FCR or FRR

Source: METIS

A more detailed description of the scenarios, how each option/measure was modelled and what were the identified relevant current practices, can be found in an explanatory technical report[35].

It is important to highlight that the scenarios under Problem Area I do not consider explicitly the possible existence of capacity mechanisms nor support schemes for RES E, focusing strictly on the wholesale market operation over the various time frames (day-ahead, intraday, balancing). Nevertheless, certain assumptions (like priority dispatch for biomass) would make economic sense only in the case of existing economic subsidies.

Figure 6: Regions used for cooperation in reserve sizing and procurement

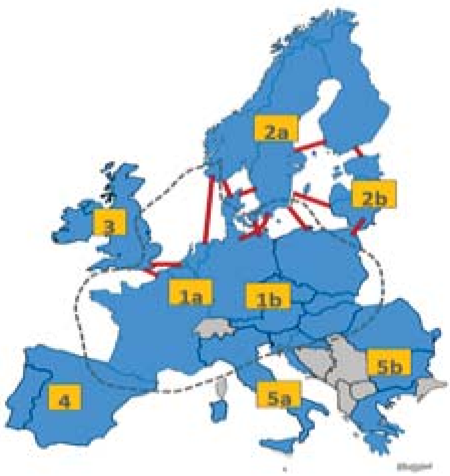
Region 1
Austria
Belgium
Czech Republic
Denmark
France
Germany
Hungary
Luxembourg
Netherlands
Poland
Slovakia
Slovenia
Switzerland

Region 3
United Kingdom
Ireland

Region 4
Portugal
Spain

Region 2
Estonia
Finland
Latvia
Lithuania
Norway
Sweden

Region 5
Bosnia and Herzegovina
Bulgaria
Croatia
Cyprus
FYR of Macedonia
Greece
Italy
Malta
Montenegro
Romania
Serbia

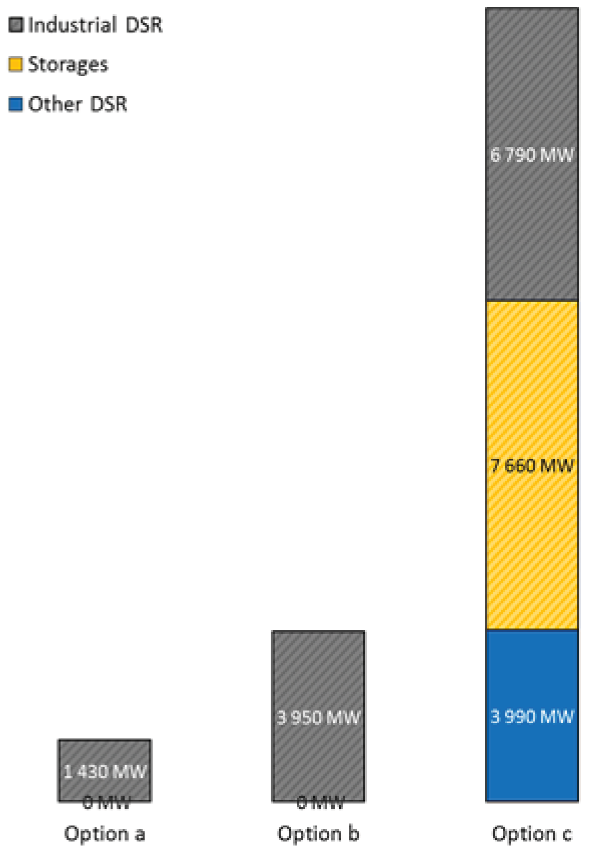


Source: METIS

[35] "*METIS Technical Note T05: METIS market module configuration for Study S12: Focus on day-ahead, intraday and balancing markets*", Artelys and THEMA Consulting (2016).

Figure 7: DR deployment in METIS for options a, b and c and current practices in DR participation in balancing markets

DSR participation in balancing markets	FCR/aFRR	mFRR
Austria	yes	yes
Belgium	NA	yes
Bulgaria	yes	yes
Croatia	no	no
Czech Republic	no	no
Denmark	yes	yes
Estonia	no	no
Finland	yes	yes
France	N/A	yes
Germany	yes	yes
Greece	no	no
Hungary	no	no
Ireland	no	no
Italy	no	no
Latvia	no	no
Lithuania	no	no
Netherlands	yes	yes
Norway	yes	yes
Poland	no	no
Portugal	yes	yes
Romania	no	no
Slovenia	N/A	no
Slovakia	no	no
Spain	no	no
Sweden	yes	yes
Switzerland	yes	yes
United Kingdom	N/A	yes



Source: METIS

PRIMES/IEM policy scenarios for the options of Problem Area II

PRIMES/IEM scenarios were setup very similarly to the METIS scenarios. As can be deduced from the description of the model, PRIMES/IEM puts more emphasis on the simulation of the bidding behaviour of market participants and the modelling of the grid, thus making it a better tool to capture the additional measures considered in Option 1 of Problem Area II (on top of Option 1(c) of Problem Area I), i.e. the removal of low price caps and the addition of locational price signals.

The consideration of market participant bidding behaviour and internal grid congestion, made it necessary to re-run the baseline (Option 0) also of Problem Area I under these new assumptions, in order to be used as the baseline of Problem Area II, with one caveat: similar to METIS, PRIMES/IEM cannot model CMs. On one hand this implies an underestimation of the benefits of the energy only market (Option 1) related to the more efficient operation of the system. On the other hand the modelled baseline could not be used for the comparison with Options 2 and 3. The approach followed to resolve this issue is described in the next section.

In order to enrich the analysis, and provide more comparability with the analysis performed for Problem Area I, it was decided to run also Options 1(a) (level playing field) and Option 1(b) (strengthening short-term markets) of Problem Area I. For the better understanding of the reader, the construction of these options is presented in a similar manner as for the METIS scenarios, highlighting that Option 0 corresponds to the baseline and Option 1(c) to Option 1 of Problem Area II. Options 1(a) (level playing field) and 1(b) (strengthening short-term markets) do not correspond to any specific option of Problem Area II, but are presented for completeness. The identification and methodology for the quantification of current practices was supported by the same study used for the METIS modelling.

Table 5: Overview of MDI impact assessment Problem Area II scenarios as modelled by PRIMES/IEM (read in conjunction with Table 4)

Action	Field	MDI options			
		0	***1(a)***	***1(b)***	**1**
1	DR deployment	a	b	b	c
2	RES E priority dispatch	a	b	c	d
3	Day-ahead and intraday liquidity	a	b	c	c
4	Intraday coupling	a	b	c	c
5	Reserve dimensioning	a	b	c	c
6	Reserve procurement methodology	a	a	b	b
7	Use of NTC and bidding zones assumption	a	a	b	b
8	Price Caps	a	b	b	b

Source: PRIMES/IEM

Table 6: Overview of the sub-options for each measure modelled in METIS

Measure	Topic	Description of the options
1	DR deployment	Three levels of DR deployment (sub-options a, b and c, with increasing economic potential, based on COWI BAU and PO2 scenarios) were considered. Assumptions were similar to METIS. As load shifting and load reductions could be captured in PRIMES/IEM, DR was modelled also for the day-ahead (not only for balancing / reserves as in METIS).
2	RES E priority dispatch	Four sub-options were considered: a. Priority dispatch for must take CHP, RES E, biomass and small-scale RES E b. As in (a), but biomass bids at marginal costs. c. As in (b), with no priority dispatch of RES E except small scale. RES E bidding at marginal costs minus FIT (wherever applicable). d. As in (c) but with no priority of small-scale RES E thanks to aggregators. Note that removal of priority dispatch is assumed to imply balance responsibility and capability to participate in intraday and offer balancing services. Thus for sub-option (d) all resources participate in intraday, offer balancing services and have balancing responsibilities.
3	Day-ahead and intraday liquidity	Three options were considered: a. Low liquidity. DAM covers part of the load, with many bilateral contracts nominated. ID illiquid in certain countries, in which case TSO has significant RR. b. Improved liquidity. DAM covers the large majority of the load, no nominations. ID illiquid in certain countries, in which case TSO has significant RR.

Measure	Topic	Description of the options
		c. Liquid markets. DAM covers the whole load. Liquid and harmonised ID markets.
4	Intraday coupling	Three options were considered: a. Very limited participation of flows over interconnectors (as available capacity for intraday is restricted to the minimum – defined by country) b. Limited participation of flows over interconnectors c. Entire physical capacity of interconnectors allocated to IDM and flow-based allocation of capacities, after taking into account remaining capacity of interconnectors.
5	Reserve dimensioning	Reserve was sized exogenously (own calculations). Three options were considered: a. High reserve requirements (national) b. High reserve requirements (national) but slightly reduced than in Option 0 c. EU-wide reserve requirements (nonetheless taking into account areas systematically congested)
6	Reserve procurement methodology	The options were: a. Current practices b. Day-ahead procurement(which was modelled in PRIMES/IEM as a joint optimization of power and reserve day-ahead procurement)
7	Use of NTC and bidding zones assumption	Two options were considered: a. Restrictive ATC (NTC – bilateral contracts – TSO reserves) – defined by country. National Bidding Zones (NTC values are given on existing border basis) b. Entire physical capacity of interconnectors allocated to DAM and flow-based allocation of capacities
8	Price Caps	Two options: a. Reflecting current practices b. Equal to VoLL, being the same for all Member States.

Source: PRIMES/IEM

PRIMES/OM policy scenarios for the options of Problem Area II

As already discussed in the previous section, the technical difficulty to model simultaneously specific wholesale market measures (removal of low price caps, locational signals for investments) with the issues on the coordination of CMs led to a two-step approach:

- Initially PRIMES/IEM was used to model Option 0 and Option 1 of Problem Area II. This was sufficient to show the benefit of Option 1.
- Subsequently PRIMES/OM was used to model Options 1 to 3 of Problem Area II, but not Option 0, this time the focus being on CMs. Comparison was performed among these three Options.

Due to the limitations of PRIMES/OM, all the detailed measures and assumptions under Option 1 could not be captured. Concerning bidding behaviour, the same approach as in PRIMES/IEM was followed. Table 7 presents a short comparison of the main results related to power generation for 2030 for the three models (PRIMES, PRIMES/IEM and PRIMES/OM).

Table 7: Comparison of results for PRIMES EUCO27, PRIMES/IEM Option 1(b) and PRIMES/OM Option 1 for 2030.

	PRIMES EUCO27	PRIMES/IEM Option 1(b)	PRIMES/OM Option 1
Net Installed Power Capacity (in MW_e)	**1,131,045**	as in EUCO27	**1,094,290**
Nuclear energy	109,905		109,905
Hydro (pumping excluded)	133,335		133,335
Wind on-shore	246,064		246,064
Wind off-shore	37,949		37,949
Solar	233,813		233,813
Biomass-waste fired	53,073		53,073
Other renewables	2,079		2,066
Solids fired	99,396		80,844
Oil fired	15,304		15,930
Gas fired	200,127		181,312
Net generation by plant type (in GWh)	**3,396,680**	**3,339,769**	**3,378,950**
Nuclear energy	738,363	678,318	737,365
Hydro (pumping excluded)	375,138	364,089	375,020
Wind on-shore	564,407	552,893	564,539
Wind off-shore	127,334	126,953	127,388
Solar	303,625	266,644	299,070
Biomass-waste fired	238,108	231,813	200,828
Other renewables	9,732	9,732	9,268
Solids fired	448,640	368,460	469,182
Oil fired	14,572	28,816[36]	11,754
Gas fired	576,760	712,051	584,537

Source: PRIMES

Apart from the differences in the installed capacities for solids and gas plants, explained in more detail in Section 6.2.6.3, the main difference is the increased generation of gas plants in detriment of solids and nuclear in PRIMES/IEM, most likely due to the better capturing of the flexibility needs of the system.

With Option 1 described above, Options 2 and 3 assume on top the inclusion of CMs for specific countries. Both Options assume CMs only in the case of Member States foreseeing adequacy problems in their markets. Therefore certain Member States needed to be chosen indicatively for this role. For the scope of this assessment, four countries were assumed to be in the need of a CM: France, Ireland, Italy and UK. This assumption was not based on a resource adequacy analysis, but on the CMs examined under DG COMP's Sector Inquiry, focusing specifically on countries with market-wide CMs.

When a country was assumed to have a CM in place, it was assumed that generators no longer followed scarcity pricing bidding behaviour, but shifted to marginal cost bidding.

[36] As the reported technology categories of PRIMES do not entirely match PRIMES/IEM, for PRIMES/IEM the reported figure in the table for oil fired generation includes peak units, steam turbines (both oil and gas) as well as CHP with oil as main fuel.

Therefore in Options 2 and 3 a hybrid market was considered for EU28, with 24 Member States having an energy only market (with scarcity pricing behaviour), while 4 Member States having and energy market (with marginal pricing behaviour) supplemented with a capacity mechanism.

Finally the only difference between Options 2 and 3, is that in Option 3 the CM is assumed to include rules foreseeing explicit participation of cross-border capacities. Cross-border capacities were assumed to participate to a CM up to a certain upper bound. The main idea for this calculation of this upper bound was similar to the concept of unforced available capacity, which is used in CMs for the generation capacities. Note though that using this concept for calculating unforced available capacity (or de-rated capacity) of interconnectors during system stress times is more complex because the probability of non-delivery is not due only to technical factors but it is mainly due to congestion factors, which can considerably vary depending on power trade circumstances during system stress times. To do this calculation it was necessary to dispose simulation results of the operation of the multi-country system. Alternatively, the calculation could be based on statistical data on system operation in past years. In both cases, the simulation requires calculation of power flows over the interconnection system.

Data collection and data gaps

The modelling performed for the impact assessment had significant data requirements. For example METIS requires about twenty different types of data (such as installed capacities, variable costs, availabilities, load factors and such). Depending on the type of simulation, over 25 million individual data points can be required for each single test case, mostly coming from hourly data (such as hourly national demands). For the NTUA models an ever larger set of data was required (multiple times larger), as PRIMES covers the whole European energy sector and all existing or emerging technologies, from household appliances to industrial processes and means of transport. The respective data were collected from public and commercial databases, as well as DG ENER EMOS database.

Moreover, in order to assess the impact of various measures and regulations aimed at improving the market functioning, one needs to compare the market outcome in the distorted situation, i.e. under current practices, with the market outcome after the implementation of new legislative measures. These distortions should be based on the current situation and practices and form the baseline for the impact assessment.

For this purpose the Commission requested assistance in the form of a study providing the necessary inputs, i.e. facts and data for the modelling of the impacts of removal of current market distortions. Although a significant amount of data was collected, a large number of desired data sets was either unavailable or undisclosed. This unavailability of data sometimes applied only for specific Member States for certain series, creating difficulties in using the collected data for the rest of the Member States. In these cases proxies need to be defined that could fill in the data gaps[37].

Modelling limitations

Every model is a simplification of reality. Thus, a model itself is not able to capture all features and facets of the real world. While one may be tempted to include as many features and options as possible, one has to be careful in order to avoid over-complication of models. This can very quickly result in overfitting (i.e. modelling relationships and cause and effects that do in this way not apply to reality, but yielding a better fit), and transparency issues (i.e. understanding in the end not the model results, or drawing wrong conclusions). It is therefore essential to find the right balance between complexity and transparency, taking the strengths and weakness of each modelling approach into account.

For these reasons, considering the limitations of each modelling approach, a number of compromises were made. There was an effort these compromises to retain the complexity of the modelling at the lowest possible level, in order to allo interpretability of results. The aforementioned study on market distortions also contributed in identifying the best modelling approaches to capture all major distortions.

One should also expect that the different models used, although all of them focus on the power sector, can produce different results due to the varying methodological approaches followed. As long as these differences are well-founded on the underlying methodology and scope of each model, while being based on the same underlying assumptions and input data, they can be considered as complementary, as they give a better overview of the impacts of the various policy options and help producing a more robust assessment.

[37] "*Electricity Market Functioning: Current Distortions, and How to Model their Removal*", COWI (2016).

Tool Concerned	Main Modelling Limitations		
	Leading to a possible overestimation of benefits	**Leading to a possible underestimation of benefits**	**With an unclear effect**
METIS & PRIMES/IEM	The baseline assumes current practices for a number of market design related measures and policies, not considering their possible evolution and the expansion of existing initiatives. As the situation is very unclear how these will advance in the coming years, and since modelling requires a specific assumption for each of these measures, it was decided for these cases (e.g. DR participation in the markets) to reflect a more pessimistic view, where only few advancements are made. In this respect the costs of the baseline are quite likely overestimated.	The detrimental effects of capacity mechanisms or support schemes for RES E to the efficiency of the electricity market operation over the various time frames, as well as the external costs to the power system (in relation to the energy market), were not considered. Still these are touched in Problem Area II and the RED II impact assessment, as well as strong indication on the impacts of RES E subsidies can be deduced by the effect of the removal of priority dispatch for biomass plants. The softer approach used for the modelling of priority dispatch of variable RES E (wind, solar) underestimates the relevant cost of the baseline scenario. Similarly for the balancing responsibility, where H-2 forecasts for RES E are used, even when balance responsibility is not assumed to apply to them. METIS did not model CHP and small scale RES E separately, which would further enhance the impacts of priority dispatch, currently assessed only for biomass.	Modelling of the day-ahead and reserve procurement is based on the so-called co-optimization of energy and reserves. This approach was the one implemented for simplicity and transparency. At the same time though it does lead to the optimal scheduling of units. This on one hand underestimates the costs of the baseline (in the case of METIS), but at the same time possibly over-estimates the benefits of the policy options. Still overall the specific choice should not be considered pivotal. Well-designed markets should lead to the same efficient operation of the power system. Liquid intraday and balancing markets should optimize operation and resolve possible infeasibility issues resulting from the DA schedule.
METIS	The yearly dimensioning and procurement of reserves overestimates the cost of current practices, not even considering their possible evolution, based on which are very likely to be brought even closer to real time in the coming years. This is partially compensated by assuming that dimensioning is performed based on the more accurate probabilistic approach (despite currently performed in many Member States based on the deterministic one). Also by the fact that in all sub-options dimensioning of mFRR and FCR does not vary (thus no benefits are reported for this).	The issue of the limited liquidity currently observed in intraday and balancing markets is not captured in the modelling. Thus METIS assumed that markets would be liquid in 2030, which may very well be indeed the case without any policy action. Note though that in certain Member States these markets may not even exist today,	Continuous intraday trading was modelled as consecutive hourly implicit auctions.
METIS		Even in the baseline, interconnector capacity is	The assumed effect of the measures on the interconnector

Tool Concerned	Main Modelling Limitations		
	Leading to a possible overestimation of benefits	Leading to a possible underestimation of benefits	With an unclear effect
		assumed to be allocated and used relatively efficiently. Moreover the absence of network modelling implied that all relevant (and in many cases significant) costs were not considered, especially related to internal congestion (within Member States).	capacities (i.e. the increase of NTC capacities) for the various options was performed in a stylized manner. It was based on very rough estimations due to the significant lack of relevant data.
METIS		DR was modelled as if participating only in balancing markets and reserves, but not in day-ahead / intraday. Benefits from load shifting or load reductions were not assessed due to the lack of sufficient detailed data. A standard load profile was used for demand, based on ENTSO-E's TYNDP 2016 assumptions. A dynamic profile for demand and storage would better capture the reactions of demand to market prices (and the associated benefits).	Stylized modelling approach concerning costs of DR.
METIS		Competition issues, effects of nominations and block-bids, as well as possible strategic behaviour of the market participants were not considered. On the contrary, perfect competition was assumed based on marginal pricing.	
PRIMES/IEM & PRIMES/OM		Assumed bidding behaviour on behalf of market participants was not considered very aggressive, with the electricity price rarely reaching the price caps.	Modelling required a significant amount of inputs and exogenous assumptions, e.g. on market behaviour etc., with data not necessarily available (generally, not just publicly).Moreover significant amount of data (e.g. detailed data on RR, nominations, technical details on the transmission grid) were missing, so had to be estimated by the modellers. Thus results are quite dependant on these inputs. Still every effort was made to confirm assumptions based on currently observed market operation data.
PRIMES/OM		The fact that the baseline does not capture the possible overcapacity in the power markets, e.g. due to existing CMs or RES E support schemes or due to unrealised forecasts of the market participants, takes	The selection of the countries assumed to have a CM may be influencing the results (in an uncertain direction). Each combination of countries could possibly lead to different results.

Tool Concerned	Main Modelling Limitations		
	Leading to a possible overestimation of benefits	**Leading to a possible underestimation of benefits**	**With an unclear effect**
		away part of the benefits that would be realised from well-functioning markets (and CMs).	For this reason a sensitivity was performed assuming the existence of CMs for all countries, and then performing the comparison of Options 2 and 3 in this context.

Annex IV: Analytical models used in preparing the impact assessment.

Annex V: Evidence and external expertise used

The present impact assessment is based on a large body of material, all of which is referenced in the footnotes. A number of studies have however been conducted mainly or specifically for this impact assessment. These are listed and described further in the table below.

The Commission (DG Competition) has also been conducting a sector inquiry into national capacity mechanisms and organised Working Groups with Member States with a view to help them implement the provisions in the EEAG related to capacity mechanisms and to share experience in the design of capacity mechanisms[38].

[38] http://ec.europa.eu/competition/sectors/energy/state_aid_to_secure_electricity_supply_en.html

Study	Study serve to study/substantiate impact of	Contractor	Published
METIS Study 12: Assessing Market Design Options in 2030.	Assessing elements for upgrading the market (all options under Problem Area I) with a focus on the more efficient operation of the power system: - Removing Market Distortions - Allocating interconnection capacity across time frames - Procurement and Sizing of Balancing Reserves Impacts of the participation of Distributed Generation in the market	Modelling tool DG ENER/METIS Consortium	To be published[39]
METIS Study 04: Stakes of a common approach for generation and system adequacy.	Assessing the benefits from a coordinated approach in Generation and System Adequacy Analysis	Modelling tool DG ENER/METIS Consortium	To be published
METIS Study 16: Weather-driven revenue uncertainty for power producers and ways to mitigate it .	Effect of weather related uncertainty to revenues. Capacity savings due to cooperation. CM coordination/cross-border participation.	Modelling tool DG ENER/METIS Consortium	To be published
METIS Technical Note T04: Methodology for the integration of PRIMES scenarios into METIS.	Technical note providing details on the methodological approach followed with METIS.	METIS Consortium	To be published
METIS Technical Note T05: METIS market module	Technical note providing details on the	METIS Consortium / Thema	To be published

[39] Once operational, the envisaged link is expected to be the following: https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis. Same applies for all METIS studies.

Study	Study serve to study/substantiate impact of	Contractor	Published
configuration for Study S12 - Focus on day-ahead, intraday and balancing markets.	methodological approach followed with METIS.	Consulting	
"*Methodology and results of modelling the EU electricity market using the PRIMES/IEM and PRIMES/OM models*"	A. Assessing elements for upgrading the market (main options under Problem Area I) with a focus on the revenues for the market players, including: - Scarcity pricing - Bidding Zones B. Assessing investment incentives and the need for coordination of CMs: - Profitability of power generation investments Coordination of CMs	NTUA	To be published
Electricity Market Functioning: Current Distortions, and How to Model Their Removal	Impact removing market distortions: - Identifying market distortions Providing data input and support for the modelling	COWI / Thema / NTUA	To be published
Framework for cross-border participation in capacity mechanisms	CM cross-border arrangements	COWI/Thema/NTUA	To be published
Transmission tariffs and Congestion income policies	Options for locational signals/regulatory framework IC construction	Trinomics	To be published

Study	Study serve to study/substantiate impact of	Contractor	Published
Integration of electricity balancing markets and regional procurement of balancing reserves	Main study supporting Balancing Guidelines IA. For MDI: regional sizing and procurement balancing reserves[40]	COWI/Artelys	To be published
Impact Assessment support Study on downstream flexibility, demand response and smart metering	Costs and benefits of measures to remove market barriers to demand response and make dynamic price tariffs more accessible	COWI / ECOFYS / THEMA / VITO	To be published
Study on future European electricity system operation	Future model TSO collaboration	Ecorys, DNV-GL,ECN	https://ec.europa.eu/energy/sites/ener/files/documents/15-3071%20DNV%20GL%20report%20Options%20for%20future%20System%20Operation.pdf
System adequacy assessment	Methodology for system adequacy assessments	JRC	To be published
Identification of Appropriate Generation and System Adequacy Standards for the Internal Electricity Market	System adequacy standards practises and methods	Mercados, E-bridge, ref4e	https://ec.europa.eu/energy/sites/ener/files/documents/Generation%20adequacy%20Final%20Report_for%20publication.pdf
Impact assessment support study on: "Policies for DSOs, Distribution Tariffs and Data Handling"	Cost and benefits of different options concerning DSO roles, distribution network tariffs, data handling models	Copenhagen Economics, and VVA	To be published
Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU	Billing information; contract exit fees; price comparison tools; disclosure and guarantees of origin	Ipsos, London Economics, and Deloitte	To be published
National policies on security of electricity supply	Review of current national rules and practices relating to risk preparedness in the area of security of electricity supply	VVA Consulting & Spark	https://ec.europa.eu/energy/sites/ener/files/documents/DG%20ENER%20Risk%20preparedness%20final%20report%20May2016.pdf
Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers	Removing market distortions by phasing-out regulated prices Appraisal of disconnection safeguards across the EU.	INSIGHT_E	To be published

40 Examines in more detail issues that are going to be examined also on METIS Study S12.

Study	Study serve to study/substantiate impact of	Contractor	Published
Energy poverty and vulnerable consumers in the energy sector across the EU: analysis of policies and measures	Review of measures to protect energy poor and vulnerable consumers	INSIGHT_E	https://ec.europa.eu/energy/sites/ener/files/documents/INSIGHT_E_Energy%20Poverty%20-%20Main%20Report_FINAL.pdf
Selecting indicators to measure energy poverty	Review, appraisal and computation of indicators to measure energy poverty	Trinomics, University College London, and 7Seven	https://ec.europa.eu/energy/sites/ener/files/documents/Selecting%20Indicators%20to%20Measure%20Energy%20Poverty.pdf
Fuel poverty in the European Union: a concept in need of definition?	Critical assessment of the pros and cons of an energy poverty definition at the EU level	Harriet Thomson, Carolyn Snell and Christine Liddell	http://extra.shu.ac.uk/ppp-online/wp-content/uploads/2016/04/fuel-poverty-european-union.pdf
The role of DSOs in a Smart Grid environment	Assessment of the future role of DSOs in specific activities	ECN & Ecorys	https://ec.europa.eu/energy/sites/ener/files/documents/20140423_dso_smartgrid.pdf
Study on the effective integration of Distributed Energy Resources for providing flexibility to the electricity system	Assessment of distributed energy resources and their effectiveness in providing flexibility to the energy system	PwC, Sweco, Ecofys, Tractebel	https://ec.europa.eu/energy/sites/ener/files/documents/5469759000%20Effective%20integration%20of%20DER%20Final%20ver%202_6%20April%202015.pdf
From Distribution Networks to Smart Distribution Systems: Rethinking the Regulation of European Electricity DSOs	Assessment of the DSO role in the context of four regulatory areas including remuneration, network tariff structure and DSO activities	THINK	http://www.eui.eu/projects/think/documents/thinktopic/topic12digital.pdf
Options on handling Smart Grids Data	Description of different data handling options for smart grids	EC Smart Grids Task Force	https://ec.europa.eu/energy/sites/ener/files/documents/xpert_group3_first_year_report.pdf
Regulatory Recommendations for the Deployment of Flexibility	Description of the flexibility context, commercial and regulatory arrangements, incentives for the development of flexibility, policy recommendations	EC Smart Grids Task Force	https://ec.europa.eu/energy/sites/ener/files/documents/EG3%20Final%20-%20January%202015.pdf
Identifying energy efficiency improvements and saving potential in energy networks and demand response	Analysis of different options for improving efficiency in energy networks according to Article 15 of the EED	Tractebel, Ecofys	https://ec.europa.eu/energy/sites/ener/files/documents/GRIDEE_4NT_364174_000_01_TOTALDOC%20-%2018-1-2016.pdf
Study on tariff design for distribution systems	Benchmarking of different distribution tariff structures and levels for electricity and gas across EU	AF Mercados, refE, Indra	https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF

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Annex VI: Evaluation

The evaluation is presented as a self-standing document.

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Annex VII: Overview of electricity network codes and guidelines

This annex provides an overview of electricity network codes and guidelines adopted or envisaged under Articles 6, 8 and 18 of the Electricity Regulation as well as a brief description to the present initiative, if any.

Electricity network codes and guidelines adopted or envisaged under Articles 6, 8 and 18 of the Electricity Regulation	State of play	Brief description of contents I	Link to MD
Commission Regulation establishing a Guideline on capacity allocation and congestion management	Adopted on 24 July 2015	Legal implementation of day-ahead and intraday market coupling, flow-based capacity calculation	Linked to short-term markets For more details, see Annex 2.2
Commission Regulation establishing a Network code on requirements for grid connection of generators	Adopted on 14 April 2016	Defines the necessary technical capabilities of generators in order to contribute to system safety and to create a level playing field.	No direct link with MD
Commission Regulation establishing a Network Code on High Voltage Direct Current Connections and DC-connected Power Park Modules	Adopted on 26 August 2016	Technical connection rules for HVDC lines, e.g. used for connections of offshore wind farms	No direct link with MD
Commission Regulation establishing a Network code on demand connection	Adopted on 17 August 2016	Defines the necessary technical specifications of demand units connected to a grid and DSOs in order to contribute to system safety and to create a level playing field.	Link to demand response and to measures on ancillary services For more details, see Annex 3.1
Commission Regulation establishing a Guideline on Forward Capacity Allocation	Adopted on 26 September 2016	Creation of hedging opportunities for the electricity market; important to facilitate cross-border trade; capacity to be allocated through auctions on a central booking platform; harmonisation of capacity products	Link to short-term markets, scarcity pricing and locational signals. See Annexes 2.2, 4.1, 4.2
Commission Regulation establishing a Guideline on electricity transmission System Operation	Text voted favourably by MS on 4 May Target date for launching scrutiny: December 2016	Rules to react to system incidents (TSO interaction when the system goes beyond acceptable operational ranges) Creation of a framework for TSO cooperation in the preparation of system operation (i.e. planning ahead of real time). Guidance for how TSOs should create a framework for keeping system frequency within safe operational ranges	Linked to TSO cooperation in the planning and operation of transmission systems. For more details, see Annex 2.3
Draft Commission Regulation establishing a Guideline on Electricity Balancing **('Balancing Guideline')**	Target for vote in comitology: by end 2016	First step to the development of common merit order lists for the activation of balancing energy and the start of a harmonisation of balancing products.	Linked to procurement rules and sizing of balancing reserves. For more details, see Annex 2.1
Draft Commission Regulation establishing a Network code on Emergency and Restoration	Target for vote in comitology: first quarter 2017	Defines requirements of the plans to be adopted by TSOs concerning procedures to be followed when blackouts happen	Linked to security of supply measures. For more details, see Annex 6

Annex VIII: Summary tables of options for detailed measures assessed under each main option

The tables provided here reflect the in-depth assessment made of the options for detailed measures described in the Annexes to the impact assessment Chapter 1.1 through to 7.6

The manner in which they correspond to the main options assessed in the present document is set out in Table 6, Table 7, Table 8 and Table 9 in the present document

Measures assessed under Problem Area 1, Option 1(a): level playing field amongst participants and resources

Priority access and dispatch

Objective: To ensure that all technologies can compete on an equal footing, eliminating provisions which create market distortions unless clear necessity is demonstrated, thus ensuring that the most efficient option for meeting the policy objectives is found. Dispatch should be based on the most economically efficient solution which respects policy objectives.				
	Option 0	Option 1	Option 2	Option 3
Description	Do nothing. This would maintain rules allowing priority dispatch and priority access for RES, indigenous fuels and CHP.	Abolish priority dispatch and priority access This option would generally require full merit order dispatch for all technologies, including RES E, indigenous fuels such as coal, and CHP. It would ensure optimum use of the available network in case of network congestion.	Priority dispatch and/or priority access only for emerging technologies and/or for very small plants: This option would entail maintaining priority dispatch and/or priority access only for small plants or emerging technologies. This could be limited to emerging RES E technologies, or also include emerging conventional technologies, such as CCS or very small CHP.	Abolish priority dispatch and introduce clear curtailment and re-dispatch rules to replace priority access. This option can be combined with Option 2, maintaining priority dispatch/access only for emerging technologies and/or for very small plants
Pros	Lowest political resistance	Efficient use of resources, clearly distinguishes market-based use of capacities and potentially subsidy-based installation of capacities, making subsidies transparent.	Certain emerging technologies require a minimum number of running hours to gather experiences. Certain small generators are currently not active on the wholesale market. In some cases, abolishing priority dispatch could thus bring significant challenges for implementation. Maintaining also priority access for these generators further facilitates their operation.	As Option 1, but also resolves other causes for lack of market transparency and discrimination potential. It also addresses concerns that abolishing priority dispatch and priority access could result in negative discrimination for renewable technologies.
Cons		Politically, it may be criticized that subsidized resources are not always used if there are lower operating cost alternatives. Adds uncertainty to the expected revenue stream, particularly for high variable cost generation.	Same as Option 1, but with less concerns about blocking potential for trying out technological developments and creating administrative effort for small installations. Especially as regards small installations, this could however result in significant loss of market efficiency if large shares of consumption were to be covered by small installations.	Legal clarity to ensure full compensation and non-discriminatory curtailment may be challenging to establish. Unless full compensation and non-discrimination is ensured, priority grid access may remain necessary also after the abolishment of priority dispatch.
Most suitable: Option 3. Abolishing priority dispatch and access exposes generators to market signals from which they have so far been shielded, and requires all generators to actively participate in the market. This requires clear and transparent rules for their market participation, in order to limit increases in capital costs and ensure a level playing field. This should be combined with Option 2: while aggregation can reduce administrative efforts related thereto, it is currently not yet sufficently developed to ensure also very small generators and/or emerging technologies could be active on a fully level playing field; they should thus be able to benefit from continuing exemptions.				

Regulatory exemptions from balancing responsibility

Objective: To ensure that all technologies can compete on an equal footing, eliminating provisions which create market distortions unless clear necessity is demonstrated, thus ensuring that the most efficient option for meeting the policy objectives is found. Each entity selling electricity on the market should be responsible for imbalances caused.				
	Option 0	**Option 1**	**Option 2**	**Option 3**
Description	Do nothing. This would maintain the status quo, expressly requiring financial balancing responsibility only under the state aid guidelines which allow for some exceptions.	Full balancing responsibility for all parties Each entity selling electricity on the market has to be a balancing responsible party and pay for imbalances caused.	Balancing responsibility with exemption possibilities for emerging technologies and/or small installations This would build on the EEAG.	Balancing responsibility, but possibility to delegate This would allow market parties to delegate the balancing responsibility to third parties. This option can be combined with the other options.
Pros	Lowest political resistance	Costs get allocated to those causing them. By creating incentives to be balanced, system stability is increased and the need for reserves and TSO interventions gets reduced. Incentives to improve e.g. weather forecasts are created.	This could allow shielding emerging technologies or small installations from the technical and administrative effort and financial risk related to balancing responsibility.	The impact of this option would depend on the scope and conditions of this delegation. A delegation on the basis of private agreements, with full financial compensation to the party accepting the balancing responsibility (e.g. an aggregator) generally keeps incentives intact.
Cons		Financial risks resulting from the operation of variable power generation (notably wind and solar power) are increased.	Shielding from balancing responsibilities creates serious concerns that wrong incentives reduce system stability and endanger market functioning. It can increase reserve needs, the costs of which are partly socialized. This is particularly relevant if those exemptions cover a significant part of the market (e.g. a high number of small RES E generators).	The impact of this option would depend on the scope and conditions of this delegation. A full and non-compensated delegation of risks e.g. to a regulated entity or the incumbent effectively eliminates the necessary incentives. Delegation to the incumbent also results in further increases to market dominance.
Most suitable: Option 2 combined with the possibility for delegation based on freely negotiated agreements.				

RES E access to provision of non-frequency ancillary services

Objective: transparent, non-discriminatory and market based framework for non-frequency ancillary services		
Option 0	**Option 1**	**Option 2**
BAU Different requirements, awarding procedures and remuneration schemes are currently used across MS. Rules and procedures are often tailored to conventional generators and do not always abide to transparency, non-discrimination. However increased penetration of RES displaces conventional generation and reduces the supply of these services.	Description Set out EU rules for a transparent, non-discriminatory and market based framework to the provision of non-frequency ancillary services that allows different market players /technology providers to compete on a level playing field.	Description Set out broad guidelines and principles for MS for the adoption of transparent, non-discriminatory and market based framework to the provision of non-frequency ancillary services.
Stronger enforcement Provisions containing reference to transparency, non-discrimination are contained in the Third Package. However, there is nothing specific to the context of non-frequency ancillary services.	Pro Accelerate adoption in MS of provisions that facilitate the participation of RES E to ancillary services as technical capabilities of RES E and other new technologies is available, main hurdle is regulatory framework. Clear regulatory landscape can trigger new revenue streams and business models for generation assets.	Pro Sets the general direction and boundaries for MS without being too prescriptive. Allows gradual phase-in of services based on local/regional needs and best practices.
	Con Resistance from MS and national authorities/operators due to the local/regional character of non-frequency ancillary services provided. Little previous experience of best practices and unclear how to monitor these services at DSO level where most RES E is connected.	Con Possibility of uneven regulatory and therefore market developments depending on how fast MS act. This creates uncertain prospects for businesses slowing down RES E penetration.
Most suitable option(s): Option 2 is best suited at the current stage of development of the internal electricity market. Ancillary services are currently procured and sometimes used in very different manners in different Member States, Furthermore, new services are being developped and new market actors (e.g. batteries) are quickly developing. Setting out detailed rules required for full harmonisation would thus preclude unknown future developments in this area, which currently is subject to almost no harmonisation.		

Measures assessed under Problem Area 1, Option 1(b) Strengthening short-term markets

Reserves sizing and procurement

Objective: define areas wider than national borders for sizing and procurement of balancing reserves				
	Option 0: business as usual	**Option 1: national sizing and procurement of balancing reserves on daily basis**	**Option 2: regional sizing and procurement of balancing reserves**	**Option 3: European sizing and procurement of balancing reserves**
Description	The baseline scenario consists of a smooth implementation of the Balancing Guideline. Existing on-going experiences will remain and be free to develop further, if so decided. However, sizing and procurement of balancing reserves will mainly remain national, frequency of procurement as foreseen in the Balancing Guideline. Active participation in the Balancing Stakeholder Group could ensure stronger enforcement of the Balancing Guideline.	This option consists in developing a binding regulation that would require TSOs to size their balancing reserves on daily probablistic methodologies. Daily calculation allows procuring lower balancing reserves and, together with daily procurement, enables participation of renewable energy sources and demand response. This option foressees separate procurement of all type of reserves between upward (i.e. increasing power output) and downward (i.e. reducing power output; offering demand reduction) products.	This option involves the setup of a binding regulation requiring TSOs to use regional platforms for the procurement of balancing reserves. Therefore this option foresees the implementation of an optimisation process for the allocation of transmission capacity between energy and balancing markets, which then implies procuring reserves only a day ahead of real time. This option would result in a higher level of coordination betwRReen European TSOs, but still relies on the concept of local responsibilities of individual balancing zones and remains compatible with current operational security principles.	This option would have a major impact on the current design of system operation procedures and responsibilities and current operational security principles. A supranational independent system operator ('EU ISO') would be responsible for sizing and procuring balancing reserves, cooperating with national TSOs. This would enable TSOs to reduce the security margin on transmission lines, thus offering more cross-zonal transmission capacity to the market and allowing for additional cross-zonal exchanges and sharing of balancing capacity.
Pros		Optimal national sizing and procurement of balancing reserves.	Regional areas for sizing and procurement of balancing reserves.	Single European balancing zone.
Cons		No cross-border optimisation of balancing reserves.	Balancing zones still based on national borders but cross-border optimisation possible.	Extensive standardisation through replacement of national systems, difficult and costly implementation.
Most suitable: Option 2. Sizing and procurement of balancing reserves across borders require firm transmission cross-zonal capacity. Such reservation might be limited by the physical topology of the European grid. Therefore, in order to reap the full potential of sharing and exchanging balancing capacity across borders, the regional approach in Option 2 is the preferred option.				

Removing distortions for liquid short-term markets

Objective: to remove any barriers that exist to liquid short-term markets, specifically in the intraday timeframe, and to ensure distortions are minimised.			
	Option 0	**Option 1**	**Option 2**
Description	Business as usual Local markets mostly unregulated, allowing for national differences, but affected by the arrangements for cross-border intraday and day-ahead market coupling. Stronger enforcement and volunatry cooperation There is limited legislation to enforce and voluntary cooperation would not provide certainty to the market	Fully harmonise all arrangements in local markets.	Selected harmonisation, specifically on issues relating to gate closure times and products.
Pros	Simplest approach, and allows the cross-border arrangements to affect local market arrangements. Likely to see a degree of harmonisation over time.	Would minimise distortions, with very limited opportunity for deviation.	Targets issues that are particularly important for maximising liquidity of short-term markets and allows for participation of demand response and small scale RES.
Cons	Differences in national markets will remain that can act as a barrier.	Extremely complex; even the cross-border arrangements have not yet been decided and need significant work from experts. Additional benefit unclear.	May still be difficult to implement in some Member States with implication on how the system is managed – central dispatch systems could, in particular, be impacted by shorter gate closure time.
Most suitable: Option 2 – Provides a proportionate response targeting those issues of most relevance.			

Improving the coordination of Transmission System Operation

Objective: Stronger coordination of Transmission System Operation at a regional level				
	Option 0	**Option 1**	**Option 2**	**Option 3**
Description	BAU Limit the TSO coordination efforts to the implementation of the new Guideline on Transmission System Operation (voted at the Electricity Cross Border Committee in May 2016 and to be adopted by end-2016) which mandates the creation of Regional Security Coordinators (RSCs) covering the whole Europe to perform five relevant tasks at regional level as a service provider to national TSOs.	Enhance the current set up of existing RSC by creating Regional Operational Centers (ROCs), centralising some additional functions at regional level over relevant geographical areas and delineating competences between ROCs and national TSOs.	Go beyond the establishment of ROCs that coexist with national TSOs and consider the creation of Regional Independent System Operators that can fully take over system operation at regional level. Transmission ownership would remain in the hands of national TSOs.	Create a European-wide Independent System Operator that can take over system operation at EU-wide level. Transmission ownership would remain in the hands of national TSOs.
Pros	Lowest political resistance.	Enlarged scope of functions assuming those tasks where centralization at regional level could bring benefits A limited number (5 max) of well-defined regions, covering the whole EU, based on the grid topology that can play an effective coordination role. One ROC will perform all functions for a given region. Enhanced cooperative decsion-making with a possibility to entrust ROCs with decision making competences on a number of issues.	Improved system and market operation leading to optimal results including optimized infrastructure development, market facilitation and use of existing infrastructure, secure real time operation.	Seamless and efficient system and market operation.
Cons	Suboptimal in the medium and long-term.	Could find political resistance towards regionalisation. If key elements/geography are not clearly enshrined in legislation, it might lead to a suboptimal outcome closer to Option 0.	Politically challenging. While this option would ultimately lead to an enhanced system operation and might not be discarded in the future, it is not considered proportionate at this stage to move directly to this option.	Extremely challenging politically. The implications of such an option would need to be carefully assessed. It is questionable whether, at least at this stage, it would be proportionate to take this step.
Most suitable option(s): Option 1 (Option 2 and Option 3 constitute the long-term vision)				

Measures assessed under Problem Area 1,Option 1(c); Pulling demand response and distributed resources into the market

Unlocking demand side response

Objective: Unlock the full potential of Demand Response			
Option O: BAU	**Option 1: Give consumers access to technologies that allow them to participate in price based Demand Response schemes**	**Option 2: as Option 1 but also fully enable incentive based Demand Response**	**Option 3: mandatory smart meter roll out and full EU framework for incentive based demand response**
Stronger enforcement of existing legislation that requires MS to roll out smart meters if a cost-benefit analysis is positive and to ensure that demand side resources can participate alongside supply in retail and wholesale markets	Give each consumer the right to request the installation of, or the upgrade to, a smart meter with all 10 recommended functionalities. Give the right to every consumer to request a dynamic electricity pricing contract.	In addition to measures described under Option 1, grant consumers access to electricity markets through their supplier or through third parties (e.g. independent aggregators) to trade their flexibility. This requires the definition of EU wide principles concerning demand response and flexibility services.	Mandatory roll out of smart meters with full functionalities to 80% of consumers by 2025 Fully harmonised rules on demand response including rules on penalties and compensation payments.
No new legislative intervention.	This option will give every consumer the right and the means (fit-for-purpose smart meter and dynamic pricing contract) to fully engage in price based DR if (s)he wishes to do so.	This option will allow price and incentive based DR as well as flexibility services to further develop across the EU. Common principles for incentive based DR will also facilitate the opening of balancing markets for cross-border trade.	This guarantees that 80% of consumers across the EU have access to fully functional smart meters by 2025 and hence can fully participate in price based DR and that market barriers for incentive based DR are removed in all MS.
Roll out of smart meters will remain limited to those MS that have a positive cost/benefit analysis. In many MS market barriers for demand response may not be fully removed and DR will not deliver to its potential.	Roll out of smart meters on a per customer basis will not allow reaping in full system-wide benefits, or benefits of economies of scale (reduced roll out costs) Incentive based demand response will not develop across Europe.	As for Option 1, access to smart meters and hence to price based DR will remain limited. Member States will continue to have freedom to design detailed market rules that may hinder the full development of Demand Response.	It ignores the fact that in 11 MS the overall costs of a large-scale roll out exceed the benefits and hence that in those MS a full roll out is not economically viable under current conditions. Fully harmonised rules on demand response cannot take into account national differences in how e.g. balancing markets are organised and may lead to suboptimal solutions.
Most suitable option(s): Option 2. Only the second option is suited to untap the potential of demand response and hence reduce overall system costs while respecting subsidiarity principles. The third option is likely to deliver the full potential of demand response but may do so at a too high cost at least in those Member States where the roll out of smart meters is not yet economically viable. Options zero and one are not likely to have a relevant impact on the development of demand response and reduction of electricity system cost.			

Distribution networks

Objective: Enable DSOs to locally manage challenges of energy transition in a cost-efficient and sustainable way, without distorting the market.		
Option: 0	**Option 1**	**Option 2**
BAU Member States are primarily responsible on deciding on the detail tasks of DSOs.	- Allow and incentivize DSOs to acquire flexibility services from distributed energy resources. - Establish specific conditions under which DSOs should use flexibility, and ensure the neutrality of DSOs when interacting with the market or consumers. - Clarify the role of DSOs only in specific tasks such as data management, the ownership and operation of local storage and electric vehicle charging infrastructure. - Establish cooperation between DSOs and TSOs on specific areas, alongside the creation of a single European DSO entity.	- Allow DSOs to use flexibility under the conditions set in Option 1. - Define specific set of tasks (allowed and not allowed) for DSOs across EU. - Enforce existing unbundling rules also to DSOs with less than 100,000 customers (small DSOs).
Pro Current framework gives more flexibility to Member States to accommodate local conditions in their national measures.	Pro Use of flexible resources by DSOs will support integration of RES E in distribution grids in a cost-efficient way. Measures which ensure neutrality of DSOs and will guarantee that operators do not take advantage of their monopolistic position in the market.	Pro Stricter unbundling rules would possibly enhance competition in distribution systems which are currently exempted from unbundling requirements. Under certain condition, stricter unbundling rules would also be a more robust way to minimizing DSO conflicts of interest given the broad range of changes to the electricity system, and the difficulty of anticipating how these changes could lead to market distortions.
Con Not all Member States are integrating required changes in order to support EU internal energy market and targets.	Con Effectiveness of measures may still depend on remuneration of DSOs and regulatory framework at national level.	Con Uniform unbundling rules across EU would have disproportionate effects especially for small DSOs. Possible impacts in terms of ownership, financing and effectiveness of small DSOs. A uniform set of tasks for DSOs would not accommodate local market conditions across EU and different distribution structures.
Most suitable option(s): Option 1 is the preferred option as it enhances the role of DSOs as active operators and ensures their neutrality without resulting in excess administrative costs.		

Remuneration of DSOs

Objective: A performance-based remuneration framework which incentivize DSOs to increase efficiencies in planning and innovative operation of their networks.		
Option: O	**Option 1**	**Option 2**
BAU Member States (NRAs) are mainly responsible on deciding on the detailed framework for remuneration of DSOs.	- Put in place key EU-wide principles and guidance regarding the remuneration of DSOs, including flexibility services in the cost-base and incentivising efficient operation and planning of grids. - Require DSO to prepare and implement multi-annual development plans, and coordinate with TSOs on such multi-annual development plans. - Require NRAs to periodically publish a set of common EU performance indicators that enable the comparison of DSOs performance and the fairness of distribution tariffs.	- Fully harmonize remuneration methodologies for all DSOs at EU level.
Pro Current framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro Performance based remuneration will incentivise DSOs to become more cost-efficient and offer better quality services. It would support integration of RES E and EU targets.	Pro A harmonized methodology would guarantee the implementation of specific principles.
Con Current EU framework provides only some general principles, and not specific guidance towards regulatory schemes which incentivize DSOs and raise efficiencies.	Con Detail implementation will still have to be realized at Member State level, which may reduce effectiveness of measures in some cases.	Con A complete harmonisation of DSO remuneration schemes would not meet the specificities of different distribution systems. Therefore, such an option would possibly have disproportionate effects while not meeting subsidiarity principle.
Most suitable option(s): Option 1 is the preferred option as it will reinforce the existing framework by providing guidance on effective remuneration schemes and enhancing transparency requirements		

Distribution network tariffs

Objective: Distribution tariffs that send accurate price signals to grid users and aim to fair allocation of distribution network costs.		
Option: 0	**Option 1**	**Option 2**
BAU Member States (NRAs) are mainly responsible on deciding on the detailed distribution tariffs.	- Impose on NRAs more detailed transparency and comparability requirements for distribution tariffs methodologies. - Put in place EU-wide principles and guidance which ensure fair, dynamic, time-dependent distribution tariffs in order to facilitate the integration of distributed energy resources and self-consumption.	- Harmonization of distribution tariffs across EU; fully harmonize distribution tariff structures at EU level for all EU DSOs, through concrete requirements for NRAs on tariff setting.
Pro Current framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro Principles regarding network tariffs will increase efficient use of the system and ensure a fairer allocation of network costs.	Pro A harmonized methodology would guarantee the implementation of specific principles.
Con Current EU framework provides only some general principles, and not specific guidance towards distribution network tariffs which effectively allocate costs and accommodate EU policies.	Con Detail implementation will still have to be realized at Member State level, which may reduce effectiveness of measures in some cases.	Con A complete harmonisation of DSO structures would not meet the specificities of different distribution systems. Therefore, such an option would possibly have disproportionate effects while not meeting subsidiarity principle.
Most suitable option(s): Option 1 is the preferred option as it will reinforce the existing framework by providing guidance on effective distribution network tariffs and enhancing transparency requirements		

Improving the institutional framework

Objective: To adapt the Institutional Framework, in particular ACER's decision-making powers and internal decision-making to the reality of integrated regional markets and the proposals of the Market Design Initiative, as well as to address the existing and anticipated regulatory gaps in the energy market.			
	Option 0	**Option 1**	**Option 2**
Description	Maintain status quo, taking into account that the implementation of network codes would bring certain small scale adjustments. However, the EU institutional framework would continue to be based on the complementarity of regulation at national and EU-level.	Adapting the institutional framework to the new realities of the electricity system and to the resulting need for additional regional cooperation as well as to addressing existing and anticipated regulatory gaps in the energy market.	Providing for more centralised institutional structures with additional powers and/or responsibilities for the involved entities.
Pros	Lowest political resistance.	Addresses the shortcomings identified and provides a pragmatic and flexible approach by combining bottom-up initiatives and top-down steering of the regulatory oversight.	Addresses the shortcomings identified with limited coordination requirements for institutional actors.
Cons	The implementation of the Third Package and network codes is not sufficient to overcome existing shortcomings of the institutional framework.	Requires strong coordination efforts between all involved institutional actors.	Significant changes to established institutional processes with the greatest financial impact and highest political resistance.
Most suitable: Option 1, as it adapts the institutional framework to the new realities of the electricity system by adopting a pragmatic approach in combining bottom-up initiatives and top-down steering of the regulatory oversight.			

Measures assessed under Problem Area 2, Option 2(1); Improved energy-only market without CMs)

Removing price caps

Objective: to ensure that prices in wholesale markets are not prevented from reflecting scarcity and the value that society places on energy.			
	Option 0: Business as usual	**Option 1: Eliminate all price caps**	**Option 2: Create obligation to set price caps, where they exist, at VoLL**
Description	Existing regulations already require harmonisation of maximum (and minimum) clearing prices in all price zones to a level which takes "into account an estimation of the value of lost load". Stronger enforcement/non-regulatory approach Enforceability of *"into account an estimation of the value of lost load"* in the CACM Guideline is not strong. Enforcement action is unlikely to be successful or expedient. Relying on stronger enforcement would leave considerable more legal uncertainty to market participants than clarifying the legal framework directly. Voluntary cooperation would not provide the market with sufficient confidence that governments would not step in restrict prices in the event of scarcity	Eliminate price caps altogether for balancing, intraday and day-ahead markets. Removes barriers for scarcity pricing Avoids setting of VoLL (for the purpose of removing negative effects of price caps).	Reinforced requirement to set price limits taking "into account an estimation of the value of lost load" Allow for technical price limits as part of market coupling, provided they do not prevent prices rising to VoLL. Establish requirements to minimise implicit price caps.
Pros	Simple to implement – leaves administration to technical implementation of the CACM Guideline.	Measure simple to implement; unequivocally and creates legal certainty.	Compatible with already existing requirement to set price limit, as provided for undert the CACM regulation, provides concrete legal clarity
Cons	Difficult to enforce; no clarity on how such clearing prices will be harmonised. Does not prevent price caps being implemented by other means.	Can be considered as non-proportional; could add significant risk to market participants and power exchanges if there are no limits.	VoLL, whilst a useful concept, is difficult to set in practice. A multitude of approaches exist and at least some degree of harmonisation will be required.
Most suitable: Option 2 - this provides a proportionate response to the issue –, it would allow for technical limits as part of market coupling and this should not restrict the markets ability to generate prices that reflect scarcity..			

Improving locational price signals

Objective: The objective is to have in place a robust process for deciding on the structure of locational price signals for investment and dispatch decisions in the EU electricity wholesale market.

	Option 0	Option 1	Option 2	Option 3
Description	Business as Usual – decision on bidding zone configuration left to the arrangements defined under the CACM Guideline or voluntary cooperation, which has, to date, retained the status quo .	Move to a nodal pricing system.	Introduce locational signals by new means, i.e. through transmission tariffs.	Improve currently existing the CACM Guideline procedure for reviewing bidding zones and introducing supranational decision-making, e.g. through ACER. This would be coupled with a strengthened requirement to avoid the reduction of cross-zonal capcity in order to resolve internal congestions.
Pros	Approach already agreed.	Theoretically, nodal pricing is the most optimal pricing system for electricity markets and networks.	Would unlock alternative means to provide locational signals for investment and dispatch decisions.	This improvement will render revisions of bidding zones a more technical decision. It will also increase the available cross-zonal capacity.
Cons	Risks maintenance of the status quo, and therefore misses the opportunity to address issues in the internal market.	Nodal pricing implies a complete, fundamental overhaul of current grid management and electricity trading arrangements with very substantial transition costs.	Incentives would be not be the result of market signals (value of electricity) but cost components set by regulatory intervention of a potentially highly political nature. Does not address the underlying difficulty of introducing locational price zones, namely the difficulties to arrive at decisions that reflect congestion instead of political borders.	Does not address a situation where the results of the bidding zone review are sub-optimal. I.e. this option only covers procedural issues.

Most suitable: Option 3 – this option will rely on a pre-established process but improve the decision-making so that decisions take into account cross-border impact of bidding zone configuration. Other options – e.g. tofundamentally change how locational signals are provided, would be dispropritionate.

Minimise investment and dispatch distortions due to transmission tariff structure

Objective: to minimise distortions on investment and dispatch patterns created by different transmission tariffs regimes.				
	Option 0: Business as usual	**Option 1: Restrict charges on producers (G-charges)**	**Option 2: Set clearer principles for transmission charges**	**Option 3: Harmonisation transmission tariffs**
Description	This option would see the status quo maintained, and transmission tariffs set according to the requirements under Directive 72 and the ITC regulation. Stronger enforcement and voluntary cooperation: There is no stronger enforcement action to be taken that would alone address the objective. Voluntary cooperation would, in part, be undertaken as part of implementation of Option 2.	This option could see the prohibition of transmission charges being levied on generators based on the amount of energy they generate (energy-based G-charges)	This option would see a requirement on ACER to develop more concrete principles on the setting of transmission tariffs, along with an elaboration of exiting provisions in the electricity regulation where appropriate.	Full harmonisation of transmission tariffs.
Pros	Pros: Minimal change; likely to receive some support for not taking any action in the short-term.	Eliminating energy-based G-charges would serve to limit distortionary effects on dispatch of generation caused by transmission tariffs. Social welfare benefits of approximately EUR 8 million per year. Would impact a minority of Member States (6-8 depending on design).	Provides an opportunity to move in the right direction whilst not risking taking the wrong decisions or introducing inefficiencies because of unknowns; consistent with a phased-approach; could eliminate any potential distortions without the need to mandate particular solutions; consistent with the introduction of legally binding provisions in the future, e.g. through implementing legislation.	Minimises distortion between Member States on both investment and dispatch; creates a level-playing field.
Cons	In the longer-term, likely to be a drive to do more and maintaining the status quo unlikely to be attractive; risks of continued divergence in national approaches.	Social welfare benefits relatively small – could be outweighed by transitional costs in the early years. Can be considered 'incomplete' as a number of other design elements of transmission tariffs contribute to distortionary effects.	Still leaves the door open for variation in national approaches; will not resolve all potential issues.	Unlikely to a proportionate response to the issues at this stage; given the technicalities involved, it could be more appropriate to introduce such measures as implementing legislation in the future.
Most suitable option(s): Option 2 – aside from some high-level requirements, given the complexity of transmission charges, the precise modalities should be set-out as part of implementing legislation in the future if and when appropriate. The value in Option 2 will be to set the path for the longer-term.				

Congestion income spending to increase cross-border capacity

Objective: The objective of any change should be to increase the amount of money spent on investments that maintain or increase available interconnection capacity				
	Option 0: Business as usual	**Option 1**	**Option 2**	**Option 3**
Description	This option would see the current situation maintained, i.e. that congestion income can be used for (a) guaranteeing the actual availability of allocated capacity or (b) maintaining or increasing interconnection capacities through network investments; and, where they cannot be efficiently used for these purposes, taken into account in the calculation of tariffs. Stronger enforcement: current rules do not allow for stronger enforcement. Voluntary cooperation: would offer no certainty that the allocation of income would change.	Further prescription on the use of congestion income, subjecting its use on anything other than (a) guaranteeing the actual availability of allocated capacity or (b) maintaining or increasing interconnection capacities (i.e. allowing it to be offset against tariffs) to harmonised rules.	Require that any income not used for (a) guaranteeing availability or (b) maintaining or increasing interconnection capacities flows into the Energy part of CEF-E or its successor, to be spent on relieving the biggest bottlenecks in the European electricity system, as evidenced by mature PCIs.	Transfer the responsibility of using the revenues resulting from congestion and not spent on either (a) guaranteeing availability or (b) maintaining capacities to the European Commission. De facto all revenues are allocated to CEF-E or successor funds to manage investments which increase interconnection capacity.
Pros	Minimal disruption to the market; consumers can benefit from tariff reductions – unclear whether benefits of better channelling income towards interconnection would provide more benefits to consumers, given that it may offset (at least in part) money spent on interconnection from other sources.	More guarantee that income will be spent on projects that increase or maintain interconnection capacity and relieve the most significant bottlenecks; could provide around 35% extra spend; approach reflects the EU-wider benefits of electricity exchange through interconnectors; can be linked to the PCI process.	Guarantees that income will be spent on projects that increase or maintain interconnection capacity and relieve the most important bottlenecks; could provide up to 35% extra spend; approach reflects the EU-wider benefits of electricity exchange through interconnectors; firm link with the PCI process.	Best guarantee that income will be spent on the biggest bottlenecks in the European electricity system, ensuring the best deal for European consumers in the longer run; approach reflects the EU-wider benefits of electricity exchange through interconnectors; to be linked to the PCI process.

Cons	Missing a potentially significant source of income which could be spent on interconnection and removing the biggest bottlenecks in the EU.	Restricts regulators in their tariff approval process and of TSOs on congestion income spending. Additional reporting arrangements will be necessary. Requires stronger role of ACER.	Restricts regulators in their tariff approval process and of TSOs on congestion income spending. Could mean that congestion income accumulated from one border is spent on a different border or different MS. Additional reporting arrangements will be necessary. Requires stronger role of ACER.	Could prove complicated to set up such an arrangement; could mean that congestion income accumulated from one border is spent on a different border or different MS. Requires a decision to apportion generated income to where needs are highest in European system. Will face national resistance. Will require additional reporting arrangements to be put in place. Requires stronger role of ACER.
Most suitable option(s): Option 2 – provides additional funding towards project which benefit the EU internal market as a whole, while still allowing for national decision making in the first instance. Considered the most proportionate response.				

Measures assessed under Problem Area 2, Option 2(2) CMs based on an EU-wide resource adequacy assessment

Improved resource adequacy methodology

Objective: Pan-European resource adequacy assessments				
	Option 0	**Option 1**	**Option 2**	**Option 3**
Description	Do nothing. National decision makers would continue to rely on purely national resource adequacy assessments which might inadequately take account of cross-border interdependencies. Due to different national methodologies, national assessments are difficult to compare.	Binding EU rules requiring TSOs to harmonise their methodologies for calculating resource adequacy + requiring MS to exclusively rely on them when arguing for CMs.	Binding EU rules requiring ENTSO-E to provide for a single methodology for calculating resource adequacy + requiring MS to exclusively rely on them when arguing for CMs.	Binding EU rules requiring ENTSO-E to carry out a single resource adequacy assessment for the EU + requiring MS to exclusively rely on it when arguing for CMs.
Pros	Stronger enforcement: Commission would continue to face difficulties to validate the assumptions underlying national methodologies including ensuing claims for Capacity Mechanisms (CMs).	National resource adequacy assessments would become more comparable.	In addition to benefits in Option 1, it would make it easier to embark on the single methodology.	In addition to benefits in Options 1 & 2, it would make sure that the national puzzles neatly add up to a European picture allowing for national/ regional/ European assessments. Results are more consistent and comparable as one entity (ENTSO-E) is running the same model for each country.
Cons		Even in the presence of harmonised methodologies national assessment would not be able to provide a regional or EU picture.	Even in the presence of a single methodology, national assessments would not be able to provide a regional or EU picture. National TSOs might be overcautious and not take appropriately cross-border interdependencies into account. Difficult to coordinate the work as the EU has 30+ TSOs.	It would potentially reduce the 'buy-in' from national TSOs who might still be needed for validating the results of ENTSO-E's work.
Most suitable option(s): Option 3 - this approach assesses best the capacity needs for resource adequacy and hence allows the Commission to effectively judge whether the proposed introduction of resource adequacy measures in single Member States is justified.				

Cross-border operation of capacity mechanisms

Objective: Framework for cross-border participation in capacity mechanisms			
	Option 0	**Option 1**	**Option 2**
Description	Do nothing. No European framework laying out the details of an effective cross-border participation in capacity mechanisms. Member States are likely to continue taking separate approaches to cross-border participation, including setting up individual arrangements with neighbouring markets.	Harmonised EU framework setting out procedures including roles and responsibilities for the involved parties (e.g. resource providers, regulators, TSOs) with a view to creating an effective cross-border participation scheme.	Option 1 + EU framework harmonising the main features of the capacity mechanisms per category of mechanism (e.g. for market-wide capacity mechanisms, reserves, …).
Pros	Stronger enforcement The Commission's Guidance on state interventions[41] and the EEAG require among others that such mechanisms are open and allow for the participation of resources from across the borders. There is no reason to believe that the EEAG framework is not enforced. To date, however, there are not many practical examples of such cross-border schemes.	It would reduce complexity and the administrative impact for market participants operating in more than one MS/bidding zone. It would remove the need for each MS to design a separate individual solution – and potentially reduce the need for bilateral negotiations between TSOs and regulators. It would preserve the properties of market coupling and ensure that the distortions of uncoordinated national mechanisms are corrected and internal market able to deliver the benefits to consumers.	In addition to benefits in Option 1, it would facilitate the effective participation of foreign capacity as it would simplify the design challenge and would probably increase overall efficiency by simplifying the range of rules market participants, regulators and system operators have to understand.
Cons	As the conclusion of individual cross-border arrangements depend on the involved parties' willingness to cooperate it is likely that this option will cement the current fragmentation of capacity mechanisms. Arranging cross-border participation on individual basis is likely to involve high transaction costs for all stakeholders (TSOs, regulators, ressource providers).	It would be a cost for TSOs and regulators which would have to agree on the rules and enforce them across the borders. These costs would be lower than in Option 0 though.	In addition to the drawback of Option 1, it would limit the choice of instruments.
Most suitable Option(s): Options 1 and 2			

41 http://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd01_en.pdf

Options for measures assessed under Problem Area 3: a new legal framework for preventing and managing crises situations

Objective: Ensure a common and coordinated approach to electricity crisis prevention and management across Member States, whilst avoiding undue government intervention					
	Option 0: Do nothing	**Option 0+: Non-regulatory approach**	**Option 1: Common minimum EU rules for prevention and crisis management**	**Option 2: Common minimum EU rules plus regional cooperation, building on Option 1**	**Option 3: Full harmonisation and full decision-making at regional level, building on Option 2**
		This option was disregarded as no means for enhanced implementation of the existing acquis nor for enhanced voluntary cooperation were identified			
Assessments	Rare/extreme risks and short-term risks related to security of supply are assessed from a national perspective. Risk identification & assessment methods differ across Member States.		Member States to identify and assess rare/extreme risks based on common risk types.	ENTSO-E to identify cross-border electricity crisis scenarios caused by rare/extreme risks, in a regional context. Resulting crisis scenarios to be discussed in the Electricity Coordination Group. Common methodology to be followed for short-term risk assessments (ENTSO-E Seasonal Outlooks and week-ahead assessments of the RSCs).	All rare/extreme risks undermining security of supply assessed at the EU level, which would be prevailing over national assessment.

Plans	Member States take measures to prevent and prepare for electricity crisis situations focusing on national approach, and without sufficiently taking into account cross-border impacts. No common approach to risk prevention & preparation (e.g., no common rules on how to tackle cybersecurity risks).		Member States to develop mandatory national Risk Preparedness Plans setting out who does what to prevent and manage electricity crisis situations. Plans to be submitted to the Commission and other Member States for consultation. Plans need to respect common minimum requirements. As regards cybersecurity, specific guidance would be developed.	Mandatory Risk Preparedness Plans including a national and a regional part. The regional part should address cross-border issues (such as joint crisis simulations, and joint arrangements for how to deal with situations of simultaneous crisis) and needs to be agreed by Member States within a region. Plans to be consulted with other Member States in each region and submitted for prior consultation and recommendations by the Electricity Coordination Group. Member States to designate a 'competent authority' as responsible body for coordination and cross-border cooperation in crisis situations. Development of a network code/guideline addressing specific rules to be followed for the cybersecurity. Extension of planning & cooperation obligations to Energy Community partners.	Mandatory Regional Risk Preparedness Plans, subject to binding opinions from the European Commission. Detailed templates for the plans to be followed. A dedicated body would be created to deal with cybersecurity in the energy sector.

Crisis management	Each Member State takes measures in reaction to crisis situations based on its own national rules and technical TSO rules. No co-ordination of actions and measures beyond the technical (system operation) level. In particular, there are no rules on how to coordinate actions in simultaneous crisis situations between adjacent markets. No systematic information-sharing (beyond the technical level).		Minimum common rules on crisis prevention and management (including the management of simultaneous electricity crisis) requiring Member States to: (i) not to unduly interference with markets; (ii) to offer assistance to others where needed, subject to financial compensation, and to; (iii) inform neighbouring Member States and the Commission, as of the moment that there are serious indications of an upcoming crisis and during a crisis.	Minimum obligation as set out in Option 1. Cooperation and assistance in crisis between Member States, in particular simultaneous crisis situations, should be agreed ex-ante; also agreements needed regarding financial compensation. This also includes agreements on where to shed load, when and to whom. Details of the cooperation and assistance arrangements and resulting compensation should be described in the Risk Preparedness Plans.	Crisis is managed according to the regional plans, including regional load-shedding plans, rules on customer categorisation, a harmonized definition of 'protected customers' and a detailed 'emergency rulebook' set forth at the EU level.
Monitoring	Monitoring of security of supply predominatly at the national level. ECG as a voluntary information exchange platform.		Systematic discussion of ENTSO-E Seasonal Outlooks in ECG and follow up of their results by Member States concerned.	Systematic monitoring of security of supply in Europe, on the basis of a fixed set of indicators and regular outlooks and reports produced by ENTSO-E, via the Electricity Coordination Group. Systematic reporting on electricity crisis events and development of best practices via the Electricity Coordination Group.	A European Standard (e.g. for EENS and LOLE) on Security of Supply could be developed to allow performance monitoring of Member States.

Pros			Minimum requirements for plans would ensure a minimum level of preparedness across EU taking into account cyber security. EU wide minimum common principles would ensure predictability in the triggers and actions taken by Member States.	Common methodology for assessments would allow comparability and ensure compatibility of SoS measures across Member States. Role of ENTSO-E and RSCs in assessment can take into account cross-border risks. Risk Preparedness Plans consisting of a national and regional part would ensure sufficient coordination while respecting national differences and competences. Minimum level of harmonization for cybersecurity throughout the EU. Designation of competent authority would lead to clear responsibilities and coordination in crsis. Common principles for crisis management and agreements regarding assistance and remuneration in simultaneous scarcity situations would provide a base for mutual trust and cooperation and prevent unjustified intervention into market operation. Enhanced role of ECG would provide adequate platform for discussion and exchange between Member States and regions.	Regional plans would ensure full coherence of actions taken in a crisis.
Cons	Lack of cooperation in risk preparedness and managing crisis may distort internal market and put at risk the security of supply of neighbouring countries.		Risk assessment and preparedness plans on national level do not take into account cross-border risks and crisis which make the plans less efficient and effective. Minimum principles of crisis management might not sufficiently adress simultaneous scarcity situations.	The coordination in the regional context requires administrative resources. Cybersecurity here only covers electricity, whereas the provisions should cover all energy sub-sectors including oil, gas and nuclear.	Regional risk preparedness plans and a detailed templates would have difficulties to fit in all national specificities. Detailed emergency rulebook might create overlaps with existing Network Codes and Guidelines.
	Most suitable: Option 2, as it provides for sufficient regional coordination in preparation and managing crisis while respecting national differences and competences.				

Measures assessed under Problem Area 4: The slow deployment of new services, low levels of service and poor retail market performance

Addressing energy poverty

Objective: Better understanding of energy poverty and disconnection protection to all consumers				
	Option: 0	**Option: 0+**	**Option 1**	**Option 2**
	BAU: sharing of good practices.	BAU: sharing of good practices and increasing the efforts to correctly implement the legislation. Voluntary collaboration across Member States to agree on scope and measurement of energy poverty.	Setting an EU framework to monitor energy poverty.	Setting a uniform EU framework to monitor energy poverty, preventative measures to avoid disconnections and disconnection winter moratorium for vulnerable consumers.
Energy poverty		EU Observatory of Energy poverty (funded until 2030).	Option 0+: EU Observatory of Energy Poverty (funded until 2030). Generic description of the term energy poverty in the legislation. Transparency in relation to the meaning of energy poverty and the number of households in a situation of energy poverty Member States to measure energy poverty. Better implementation of the current provisions.	Option 0+: EU Observatory of Energy Poverty (funded until 2030). Specific definition of energy poverty based on a share of income spent on energy. Member States to measure energy poverty using required energy. Better implementation and transparency as in Option 1.
Disconnection safeguards		NRAs to monitor and report figures on disconnections.	NRAs to monitor and report figures on disconnections.	NRAs to monitor and report figures of disconnections. A minimum notification period before a disconnection. All customers to receive information on the sources of support and be offered the possibility to delay payments or restructure their debts, prior to disconnection. Winter moratorium of disconnections for vulnerable consumers.
Pros	Continuous knowledge exchange.	Stronger enforcement of current legislation and continuous knowledge exchange.	Clarity on the concept and measuring of energy poverty across the EU.	Standardised energy poverty concept and metric which enables monitoring of energy poverty at EU level. Equip MS with the tools to reduce disconnections.
Cons	Existing shortcomings of the legislation are not addressed: lack of clarity of the concept of energy poverty and the number of energy	Insufficient to address the shortcomings of the current legislation with regard to energy poverty and targeted	New legislative proposal necessary. Administrative costs.	New legislative proposal necessary. Higher administrative costs. Potential conflict with principle of subsidiarity. Specific definition of energy poverty may not be

	poor households persist. Energy poverty remains a vague concept leaving space for MS to continue inefficient practices such as regulated prices. Indirect measure that could be viewed as positive but insufficient by key stakeholders.	protection.		suitable for all MS. Safeguards against disconnection may result in higher costs for companies which may be passed to consumers. Safeguards against disconnection may also result in market distortions where new suppliers avoid entering markets where risks of disconnections are significant and the suppliers active in such markets raise margins for all consumers in order to recoup losses from unpaid bills. Moratorium of disconnection may conflict with freedom of contract.
Most suitable option: Option 1 is recommended as the most balanced package of measures in terms of the cost of measures and the associated benefits. Option 1 will result in a clear framework that will allow the EU and Member States to measure and monitor the level of energy poverty across the EU. The impact assessment found that the propose disconnection safeguards in Option 2 come at a cost. There is potential to develop these measures at the EU level. However, Member States may be better suited to design these schemes to ensure that synergies between national social services and disconnection safeguards can be achieved. Please note that Option 1 and Option 2 also include the measures described in Option 0+.				

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Phasing out regulated prices

Objective: Removing market distortions by achieving the phase-out of supply price regulation for all customers.			
Option: 0	**Option 1**	**Option 2a**	**Option 2b**
Making use of existing *acquis* to continue bilateral consultations and enforcement actions to restrict price regulation to proportionate situations justified by general economic interest, accompanied by EU guidance on the interpretation of the current acquis.	Requiring MS to progressively phase out price regulation for households by a deadline specified in new EU legislation, starting with prices below costs, while allowing transitional, targeted price regulation for vulnerable customers (e. g. in the form of social tariffs).	Requiring MS to progressively phase out price regulation, starting with prices below costs, for households above a certain consumption threshold to be defined in new EU legislation or by MS.	Requiring MS to progressively phase out below cost price regulation for households by a deadline specified in new EU legislation.
Pros: - Allows a case-by-case assessment of the proportionality of price regulation, taking into account social and economic particularities in MS	Pros: - Removes the distortive effect of price regulation after the target date. - Ensures regulatory predictability and transparency for supply activities across the EU.	Pros: - Limits the distortive effect of price regulation. - Would reduce the scope of price regulation therefore limiting its distortive impact on the market.	Pros: - Limits the distortive effect of price regulation and tackles tariff deficits where existent.
Cons: - Leads to different national regimes following case-by-case assessments. This would maintain a fragmented regulatory framework across the EU which translates into administrative costs for entering new markets.	Cons: - Difficult to take into account social and economic particularities in MS in setting up a common deadline for price deregulation.	Cons: - Difficult to take into account social and economic particularities in MS in defining a common consumption threshold above which prices should be deregulated.	Cons: - Defining cost coverage at EU level is economically and legally challenging. - Implementation implies considerable regulatory and administrative impact. - Price regulation even if above cost risks holding back investments in product innovation and service quality.
Most suitable option(s): Option 1 - Setting an end date for all price intervention would ensure the complete removal of market distortions related to end-user price regulation and help create a level playing field for supply activities across the EU while allowing targeted protection for vulnerable customers and/or energy poor.			

Level playing field for access to data

Objective: Creating a level playing field for access to data.		
Option: 0	**Option 1**	**Option 2**
BAU Member States are primarily responsible on deciding roles and responsibilities in data handling.	- Define responsibilities in data handling based on appropriate definitions in the EU legislation. - Define criteria and set principles in order to ensure the impartiality and non-discriminatory behaviour of entities involved in data handling, as well as timely and transparent access to data. - Ensure that Member States implement a standardised data format at national level.	- Impose a specific EU data management model (e.g. an independent central data hub) - Define specific procedures and roles for the operation of such model.
Pro Existing framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro The above measures can be applied independently of the data management model that each Member State has chosen. The measures will increase transparency, guarantee non-discriminatory access and improve competition, while ensuring data protection.	Pro Possible simplification of models across EU and easier enforcement of standardized rules.
Con The current EU framework is too general when it comes to responsibilities and principles. It is not fit for developments which result from the deployment of smart metering systems.	Con	Con High adaptation costs for Member States who have already decided and implementing specific data management models. Such a measure would disproportionally affect those Member States that have chosen a different model without necessarily improving performance. A specific model would not necessarily fit to all Member States, where solutions which take into account local conditions may prove to be more cost-efficient and effective.
Most suitable option(s): Option 1 is the preferred option as it will improve current framework and set principles for transparent and non-discriminatory data access from eligible market parties. This option is expected to have a high net benefit for service providers and consumers and increase competition in the retail market.		

Facilitating supplier switching

Objective: Facilitating supplier switching by limiting the scope of switching and exit fees, and making them more visible and easier to understand in the event that they are used.			
Option 0	**Option 0+**	**Option 1**	**Option 2**
BAU/Stronger enforcement	Stronger enforcement, following the clarification of certain concrete requirements in the current legislation through an interpretative note.	Legislation to define and outlaw all fees to EU household consumers associated with switching suppliers, apart from: 1) exit fees for fixed-term supply contracts; 2) fees associated with energy efficiency or other bundled energy services or investments. For both exceptions, exit fees must be cost-reflective.	Legislation to define and outlaw all fees to EU household consumers associated with switching suppliers.
Pros: - Evidence may suggest a degree of non-enforcement of existing legislation by national authorities. - No new legislative intervention necessary.	Pros: - Non-enforcement may be due to complex existing legislation. - No new legislative intervention necessary.	Pros: - Considerably reduces the prevalence of fees associated with switching suppliers, and hence financial/psychological barriers to switching.	Pros: - Completely eliminates one financial/psychological barrier to switching. - Simple measure removes doubt amongst consumers. - The clearest, most enforceable requirement without exceptions.
Cons: - Continued ambiguity in existing legislation may impede enforcement. - The vast majority of switching-related fees faced by consumers are permitted under current EU legislation.	Cons: - The vast majority of switching-related fees faced by consumers are permitted under current EU legislation. - Certain MS might ignore the interpretative note.	Cons: - Marginally reduces the range of contracts available to consumers, thereby limiting innovation. - An element of interpretation remains around exceptions to the ban on fees associated with switching suppliers.	Cons: - Would further restrict innovation and consumer choice, notably regarding financing options for beneficial investments in energy equipment as part of innovative supply products e.g. self-generation, energy efficiency, etc. - Impedes the EU's decarbonisation objectives, albeit marginally.
Most suitable option(s): Option 1 is the preferred option, as it represents the most favourable balance between probable benefits and costs.			

Comparison tools

Objective: Facilitating supplier switching by improving consumer access to reliable comparison tools.		
Option 0+	**Option 1**	**Option 2**
Cross-sectorial Commission guidance addressing the applicability of the Unfair Commercial Practices Directive to comparison tools	Legislation to ensure every Member State has at least one 'certified' comparison tool that complies with pre-specified criteria on reliability and impartiality	Legislation to ensure every Member State appoints an independent body to provide a comparison tool that serves the consumer interest
Pros: - Facilitates coherent enforcement of existing legislation. - Light intervention and administrative impact. - Cross-sectorial consumer legislation already requires comparison tools to be transparent towards consumers in their functioning so as not to mislead consumers (e.g. ensure that advertising and sponsored results are properly identifiable etc.). - Cross-sectorial approach addresses shortcomings in commercial comparison tools of all varieties. - Cross-sectorial approach minimizes proliferation of sector-specific legislation.	Pros: - Fills gaps in existing legislation vis-à-vis energy comparison tools. - Limited intervention in the market, in most cases. - Allows certifying all existing energy comparison tools regardless of ownership. - Proactively increases levels of consumer trust. - Ensures EU wide access. - The certified comparison websites can become market benchmarks, foster best practices among competitors	Pros: - NRAs able to censure suppliers by removing their offers from the comparison tool. - No obligation on private sector. - Reduces risks of favouritism in certification process. - Proactively increases levels of consumer trust.
Cons: - Does not apply to non-profit comparison tools. - Does not proactively increase levels of consumer trust. - The existing legislation does not oblige comparison tools to be fully impartial, comprehensive, effective or useful to the consumer.	Cons: - Existing legislation already requires commercial comparison tools to abide by certain of the criteria addressed by certification. - Requires resources for verification and/or certification. - Significant public intervention necessary if no comparison tools in a given MS meet standards.	Cons: - To be effective, Member States must provide sufficient resources for the development of such tools to match the quality of offerings from the private sector. - Well-performing for-profit tools could be side-lined by less effective ones run by national authorities.
Most suitable option(s): Option 1 is the preferred option because it strikes the best balance between consumer welfare and administrative impact. It also gives Member States control over whether they feel a certification scheme or a publicly-run comparison tool best ensures consumer engagement in their markets.		

Improving billing information

Objective: Ensuring that all consumer bills prominently display a minimum set of information that is essential to actively participating in the market.			
Option: 0	**Option 0+**	**Option 1**	**Option 2**
BAU/Stronger enforcement	Commission recommendation on billing information	More detailed legal requirements on the key information to be included in bills	A fully standardized 'comparability box' in bills
Pros: - 77% of energy consumers agree or strongly agree that bills are "easy and clear to understand". - Allows 'natural experiments' and other innovation on the design of billing information to be developed by MS. - Recent (2014) transposition of the EED means premature to address information on energy consumption and costs.	Pros: - Low administrative impact - Gives MS significant flexibility to adapt their requirements to national conditions. - Allows best practices to further develop.	Pros: - Ensures that the minimum baseline of existing practices is clarified and raised. - Allows best practices to further develop, albeit less than Option 0. - Improves comparability and portability of information. - Ensures consumers can easily find the information elements needed to facilitate switching. - Bill design left free to innovation.	Pros: - Highest legal clarity and comparability of offers and bills. - A level playing field for all consumers and suppliers across the EU. - Very little leeway for suppliers to differently interpret the legislation with regards to the presentation of information. - Ensures consumers can easily find the information elements needed to facilitate switching.
Cons: - Poor consumer awareness of market-relevant information can be expected to continue. - Does not respond to stakeholder feedback on need to ensure minimum standards.	Cons: - A recommendation is unenforceable and may be ignored by MS/utilities. - Poor consumer awareness of market-relevant information can be expected to continue. - Does not respond to stakeholder feedback on need to ensure minimum standards.	Cons: - Limits innovation around certain bill elements. - Remaining leeway in interpreting legal articles may lead to implementation and enforcement difficulties.	Cons: - Challenging to devise standard presentation which can accommodate differences between national markets. - Highest administrative impact. - Prescriptive approach prevents beneficial innovation. - Difficult to adapt bills to evolving technologies and consumer preferences.
Most suitable option(s): Option 1 is the preferred option as it likely to leads to significant economic benefits and increased consumer surplus without significant administrative costs or the risk of overly-prescriptive legislation at the EU level.			

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EUROPEAN
COMMISSION

Brussels, 30.11.2016
SWD(2016) 410 final

PART 3/5

COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT

Accompanying the document

Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast)

Proposal for a Regulation of the European Parliament and of the Council on the electricity market (recast)

Proposal for a Regulation of the European Parliament and of the Council establishing a European Union Agency for the Cooperation of Energy Regulators (recast)

Proposal for a Regulation of the European Parliament and of the Council on risk preparedness in the electricity sector

{COM(2016) 861 final}
{SWD(2016) 411 final}
{SWD(2016) 412 final}
{SWD(2016) 413 final}

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1. DETAILED MEASURES ASSESSED UNDER PROBLEM AREA I, OPTION 1(A): LEVEL PLAYING FIELD AMONGST PARTICIPANTS AND RESOURCES

1.1. Priority access and dispatch

1.1.1. *Summary table*

Objective: To ensure that all technologies can compete on an equal footing, eliminating provisions which create market distortions unless clear necessity is demonstrated, thus ensuring that the most efficient option for meeting the policy objectives is found. Dispatch should be based on the most economically efficient solution which respects policy objectives.

	Option 0	Option 1	Option 2	Option 3
Description	Do nothing. This would maintain rules allowing priority dispatch and priority access for RES, indigenous fuels and CHP.	Abolish priority dispatch and priority access This option would generally require full merit order dispatch for all technologies, including RES E, indigenous fuels such as coal, and CHP. It would ensure optimum use of the available network in case of network congestion.	Priority dispatch and/or priority access only for emerging technologies and/or for very small plants: This option would entail maintaining priority dispatch and/or priority access only for small plants or emerging technologies. This could be limited to emerging RES E technologies, or also include emerging conventional technologies, such as CCS or very small CHP.	Abolish priority dispatch and introduce clear curtailment and re-dispatch rules to replace priority access. This option can be combined with Option 2, maintaining priority dispatch/access only for emerging technologies and/or for very small plants
Pros	Lowest political resistance	Efficient use of resources, clearly distinguishes market-based use of capacities and potentially subsidy-based installation of capacities, making subsidies transparent.	Certain emerging technologies require a minimum number of running hours to gather experiences. Certain small generators are currently not active on the wholesale market. In some cases, abolishing priority dispatch could thus bring significant challenges for implementation. Maintaining also priority access for these generators further facilitates their operation.	As Option 1, but also resolves other causes for lack of market transparency and discrimination potential. It also addresses concerns that abolishing priority dispatch and priority access could result in negative discrimination for renewable technologies.
Cons		Politically, it may be criticized that subsidized resources are not always used if there are lower operating cost alternatives. Adds uncertainty to the expected revenue stream, particularly for high variable cost generation.	Same as Option 1, but with less concerns about blocking potential for trying out technological developments and creating administrative effort for small installations. Especially as regards small installations, this could however result in significant loss of market efficiency if large shares of consumption were to be covered by small installations.	Legal clarity to ensure full compensation and non-discriminatory curtailment may be challenging to establish. Unless full compensation and non-discrimination is ensured, priority grid access may remain necessary also after the abolishment of priority dispatch.

Most suitable option(s): Option 3. Abolishing priority dispatch and access exposes generators to market signals from which they have so far been shielded, and requires all generators to actively participate in the market. This requires clear and transparent rules for their market participation, in order to limit increases in capital costs and ensure a level playing field. This should be combined with Option 2: while aggregation can reduce administrative efforts related thereto, it is currently not yet sufficently developed to ensure also very small generators and/or emerging technologies could be active on a fully level playing field; they should thus be able to benefit from continuing exemptions.

1.1.2. *Description of the baseline*

Dispatch rules determine which power generation facilities shall generate power at which time of the day. In principle, this is based on the so-called merit order, which means that those power plants which for a given time period require the lowest payment to generate electricity are called upon to generate electricity. This is determined by the day-ahead and intraday markets. In most Member States, dispatch is then first decided by market results and, where system stability requires intervention, corrected by the TSO (so-called self-dispatch systems). In some Member States (e.g. Poland) the TSO integrates both steps, directly determining on the basis of the system capabilities and market offers made which offers can be accepted (so-called central dispatch).

Access rules determine which generator gets, in case of congestion on a particular grid element, access to the electricity network. They thus do not relate to the initial network connection, but to the allocation of capacity in situations where the network is unable to fully accommodate the market result. Priority access can thus mean that in situations of congestion, instead of applying the most efficient way of remedying a particular network issue, the transmission system operator has to opt for less efficient, more complex and/or more costly options, to maintain full generation from the priority power plant.

Currently, several Directives allow the possibility or even set the obligation for Member States to include priority dispatch and priority grid access of certain technologies in their national legislation:

- Article 15(4) of the Electricity Directive provides that Member States may foresee priority dispatch of generation facilities using fuel from indigenous primary energy fuel sources to an extent not exceeding, in any calendar year, 15 % of the overall primary energy necessary to produce the electricity consumed in the Member State concerned;
- Article 16(2)(a) of the Renewable Energies Directive obliges Member States to provide for either priority access or guaranteed access to the grid-system of electricity produced from renewable energy sources;
- Article 16(2)(c) of the Renewable Energies Directive obliges Member States to ensure that when dispatching electricity generating installations, transmission system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria;
- Similarly to the provisions under the Renewable Energies Directive, Article 15 (5) b) and c) of the Energy Efficiency Directive foresee priority grid access and priority dispatch of electricity from high-efficiency cogeneration respectively.

The introduction of priority dispatch and priority access for renewable energies on the one hand and for CHP on the other hand are closely related. According to the impact assessment of the Energy Efficiency Directive, Article 15 (5) aims at ensuring a level playing field in electricity markets and help distributed CHP. Thus, the obligation of priority dispatch, and the right to priority access, already existing under its predecessor, Directive 2004/8/EC, have been expanded in the Energy Efficiency Directive to include mandatory priority access for CHP[1]. The new provision fully mirrored the provision under the then new Renewable Energies Directive.

Already for Directive 2004/8/EC, priority dispatch and (the right for a Member State to foresee) priority access were based on the "need to ensure a level playing field" and the challenges for CHP being similar to those for renewable energies. The provision of priority dispatch and priority access for CHP has thus since its beginning been closely related to the provision of these rights to renewable energies. This is also reflected in the text of Article 15(5) itself, which provides that "w*hen providing priority access or dispatch for high-efficiency cogeneration, Member States may set rankings as between, and within different types of, renewable energy and high-efficiency cogeneration and shall in any case ensure that priority access or dispatch for energy from variable renewable energy sources is not hampered.*"

The current framework thus provides that the provision of priority dispatch and priority access for CHP shall under no circumstance endanger the expansion of renewable energies. Against this background, any change to the framework for renewable energies would directly impact the justification underlying the introduction of priority dispatch and priority access for CHP.

The degree to which Member States have made use of the right under Article 15 (4) of the Electricity Directive differs significantly. Some Member States make no use of it whereas other Member States provide for priority dispatch of power generation facilities using national resources (most notably coal). The provisions in the Renewable Energy Directive and Energy Efficiency Directive are mandatory and in principle applied in all Member States, although the implementation can differ significantly due to differences in national subsidy schemes.

1.1.3. *Deficiencies of the current legislation*

European legislation allows the option (as regards indigenous resources) or sets an obligation (for RES E and CHP) to implement priority dispatch and (for RES E and CHP) priority grid access. This creates a framework with very high predictability of the total power generation per year, thus increasing investment security. In particular in view of the increasing share of RES E, this has resulted in a situation where in some Member States very high shares of power generation are coming from "prioritized" sources.

The EU has committed to a continued increase of the share of renewable generation for the coming decades. Until 2030, at least 27 % of final energy consumption in the EU shall come from RES E – this requires a share of at least 45 % in power generation[2]. According to the PRIMES EuCo27 scenario, decarbonisation of EU's energy system would require a share of RES in power generation of close to 50%, wind and solar energy alone projected to cover 29 % of power generation.

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[1] https://ec.europa.eu/energy/sites/ener/files/documents/sec_2011_0779_impact_assessment.pdf, p.58.

[2] 2030 Communication, COM(2014) 15 final, p.6.

Today, investments in renewable generation make up the largest share of investments; many RES E technologies can no longer be treated as marginal or emerging technologies.

The comparison of Germany and Denmark, two Member States with high shares both of RES E and CHP, is helpful to assess the deficiencies of systems based on strong priority dispatch and priority access principles. Taking the example of Denmark, an average of 62 % of power demand in the month of January 2014 has come from wind generation alone[3] and the share of annual demand covered by wind power has risen from 19 % in 2009 to 42 % in 2015[4]. Adding to this the share of 50.6 % of CHP in total Danish power generation[5], which makes Denmark one of the Member States with the highest share of CHP[6], in many periods almost all generation would be subject to "priority dispatch". Finally, it may be necessary to add certain generation assets which are needed to operate for system security, e.g. because only they can provide certain system services (e.g. voltage control, spinning reserves), further limiting the scope for fully market based generation. However, in Denmark, market incentives on generators are set in a way that drastically reduces the impact of priority dispatch. Almost all decentralized CHP plants and a large number of wind turbines would be exposed to and are not willing to run at negative prices. As CHP are not shielded from market signals by national support systems, they have strong incentives to stop electricity generation in times of oversupply. The integration of a high share of RES E and CHP in parallel has been successful to a significant extent because CHP are *not* built and operated on the basis of a "must run" model, where heat demand steers electricity generation. To the contrary, CHP plants have back-up solutions (boilers, heat storage), and use these where this is more efficient for the electricity system as expressed by wholesale prices.

Taking the example of another "renewables front runner", Germany, "must run" conventional power plants have been found to contribute significantly to negative prices in hours of high renewable generation and low load, with at least 20 GW of conventional generation still active even at significantly negative prices[7]. Financial incentives are so that many conventional plants generate even at significantly negative prices, with many power plants switching off electricity generation only at prices around minus 60 EUR/MWh. This increases the occurrence of negative prices, worsening the financial outlook for both renewable and conventional generators, and can increase system stress and costs of interventions by the system operator. This is not due to technical reasons – also in Germany, CHP plants generally have back-up heat capacities, which are already necessary to address e.g. maintenance periods of the main plant, or could technically install these. While it may be economically and environmentally efficient to run through short periods of low prices (to avoid ramping up or down), this is no longer the case

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3 http://www.martinot.info/renewables2050/how-is-denmark-integrating-and-balancing-renewable-energy-today.

4 http://www.energinet.dk/EN/El/Nyheder/Sider/Dansk-vindstroem-slaar-igen-rekord-42-procent.aspx.

5 https://ec.europa.eu/energy/sites/ener/files/documents/PocketBook_ENERGY_2015%20PDF%20final.pdf, p. 183.

6 http://www.code2-project.eu/wp-content/uploads/Code-2-D5-1-Final-non-pilor-Roadmap-Denmark_f2.pdf;

7 See: http://www.netztransparenz.de/de/Studie-konventionelle-Mindesterzeugung.htm

where the market is willing to pay a lot for electricity being *not* generated. Excess electricity is in these situations not very efficiently generated, but essentially a waste product. While there is a wide range of reasons for conventional generation to produce at hours of negative prices (e.g. very inflexible technologies such as nuclear or lignite which need a long time to reactivate), approximately 50 % of the plants in such a situation in Germany had at least the capability for parallel heat production, and approximately 8-10 % of conventional plants still producing at such moments were found to be heat-controlled CHP generation[8].

In view of the EU target for at least 27 % of renewable energies in final energy consumption (which according to PRIMES EuCo27 projections would require 47 % of gross final electricity consumption to come from renewable energy), the high share of priority dispatch and priority access-technologies will increasingly occur in other Member States. This can have very significant impact on the well-functioning of the electricity market. In particular:

- Subsidy schemes based on priority dispatch (such as Feed-in Tariffs) often are based on high running hours and a mitigation of market signals to the subsidized generator. This means that non-subsidized generation is increasingly pushed out of the market even where this is not cost-efficient;
- Situations in which more than 100 % of demand is covered by priority dispatch become more prevalent. This lowers the investment security provided by priority dispatch, and can lead to results contrary to policy interests such as unnecessary curtailment of RES E;
- The internal energy market depends on steering the use of generation by price signals. In a situation where the clear majority of power generation does not react to price signals, market integration fails and market signals cannot develop;
- Incentives to invest into increased flexibility which would naturally result from price signals on a functioning wholesale market do not reach a significant part of the generation mix. Priority dispatch rules can eliminate incentives for flexible generation (e.g. biomass, some CHP with back-up installations) to use the flexibility potential and instead create incentives to run independent of market demand;
- Priority dispatch and priority grid access limit the choice for transmission system operators to intervene in the system (e.g. in case of congestion on certain parts of the electricity grid). This can result in less efficient interventions (e.g. re-dispatching power plants in suboptimal locations). The increased complexity with high shares of priority dispatch could also lower system stability, although emergency measures may also affect generation benefiting from priority dispatch;
- Priority dispatch rules for high marginal cost technologies can result in using costly primary ressources to generate electricity at a time where other, cheaper, technologies were available;

[8] Consentec, *"Konventionelle Mindesterzeugung – Einordnung, aktueller Stand und perspektivische Behandlung"*, Abschlussbericht 25. Januar 2016, p. vii and 25.

- Priority dispatch rules for generation installations using indigenous ressources result in clear discrimination of cross-border flows and distortions to the internal market.

Against this background, the provision of priority dispatch and priority grid access needs to be reassessed in view of the main policy objectives of sustainability, security of supply and competitiveness (see also Section 7.4.2 of the evaluation).

1.1.4. *Presentation of the options*

For the operation of generation assets, it is recognized that the wholesale market with merit-order based dispatch and access ensures an optimal use of generation resources. Especially in balancing, it also ensures optimal use of congested network capacities. Rules which deviate from these provisions reduce system efficiency and result in market distortions, as it can sometimes be economically more efficient to curtail RES and the guarantee of non-curtailment significantly increases price volatility[9]. Where financial compensation on market-based principles is foreseen in case of re-dispatch, priority dispatch also does not appear to be necessary to mitigate investor risk in low marginal cost technologies. Thus, it is proposed to abolish or at least significantly limit the exceptions foreseen under EU law from merit-order based dispatch and network access.

Option 0: do nothing

This option does not change the legislative framework. Priority dispatch and access provisions remain unchanged in EU legislation and the above-described problems persist.

Option 0+: Non-regulatory approach

Stronger enforcement would not adress the policy objectives. In fact, as the objective is to ensure market-based use of generation assets with limited exceptions, stricter enforcement of existing obligations under EU law which make those exceptions mandatory would be counter-productive.

Voluntary cooperation does not change the legislative framework and thus maintains the currently existing obligations. The order of dispatch for power plants and access to the grid has clear cross-border implications. Priority dispatch/access often results in lower availability of cross-border capacities, and significant differences in these rules can thus distort cross-border trade.

Option 1: Abolish priority dispatch and priority access

Under this option, priority dispatch / priority access provisions would be removed from EU legislation, and replaced by a general principle that generation and demand response shall be dispatched on the basis of using the most efficient resources available, as determined on the basis of merit order and system capabilities.

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[9] KEMA study commissioned for the EU Commission (ENER/C1/427-2010, Final report of 12 June 2014), p.183 f.

This option would optimally achieve the defined objectives and thus be highly effective. It would however result in additional administrative impact for very small RES E installations which are currently not capable of controlling their feed-in into the grid (notably rooftop solar) and micro-CHP installations. Furthermore, it could increase complexity and prolong the development time for emerging technologies. As these technologies would not yet be mature they would not be able to generate at competitive prices and could thus not reach a number of running hours needed to generate sufficient experience.

Option 2: Limit priority dispatch and/or priority access to emerging technologies and/or small plants

Under this option, priority shall be given only where it can be justified to enable a certain technology or operating model which is seen as beneficiary under other policy objectives. As regards emerging technologies[10], this could in particular be linked to ensuring that the technologies reach a minimum number of running hours as required to gather experience with the non-mature technology. For particularly small generation installations[11], this could reduce the administrative and technical effort linked to dispatching the power plant for its owner, which may appear disproportionate for certain installations. This being said, the administrative effort can be significantly reduced by ensuring the possibility of aggregation, allowing the joint operation and management of a large number of small plants. To mitigate negative impacts on market functioning, both possible exemptions should be capped to ensure that priority dispatch and priority access does not apply to large parts of total power generation.

This option would achieve the defined objectives, although certain trade-offs would be made. Accepting priority dispatch and access for certain installations would reduce market efficiency. If the share of exempted installations in the total electricity market remains low, the negative market impact is however likely to remain very limited. On the other hand, the positive impact of allowing the development of new technologies can provide a significant benefit for the achievement of renewable energy targets in the medium to long-term. Exempting very small installations would also increase public acceptance and reduce administrative efforts required from the operators of these installations, which are often households. This is thus the preferred option, although it has to be ensured that exemptions remain limited to a small part of the market. The exact definition of the emerging technologies could be left to subsidiarity.

Option 3: Abolish priority dispatch and introduce clear curtailment and re-dispatch rules to replace priority access

This option (which can be combined with Option 2) would entail the abolishment of priority dispatch. Priority grid access would be replaced by clear rules on how to deal

[10] In the PRIMES EuCo27 scenario, the emerging technologies of tidal and solar thermal generation (other technologies having insignificant shares) are projected to have a total installed capacity of 7.26 GW and produce 10 TWh of electricity in 2030 (13 GW and 20 TWh in 2050, respectively).

[11] In the PRIMES EuCo27 scenario, RES E small-scale capacity is projected in 2030 to be 85 GW (7.8 % share) and produce 96 TWh of energy (2.9% share).

with situations of system stress, in particular as regards congestion of grid elements. In principle, market-based ressources should be used first, thus curtailing or redispatching first those generators which offer to do this against market-based compensation. In a second step, where no market-based ressources can be used, minimum rules on compensation are foreseen, ensuring compensation based on additional costs or (where this is higher) a high percentage of lost revenues.

It would mean that network operators would obtain a clear incentive to make an assessment on the basis of costs as to the alternatives available to them to address the underlying network constraints, thereby creating opportunities for more innovative solutions such as storage.

The increase in transparency and legal certainty would notably also prevent discrimination against certain technologies (particularly RES E) in curtailment and re-dispatch decisions. RES E are often operated by smaller market players, who could otherwise be subject to excessive curtailment or unable to achieve fully equal compensation. It would also foresee principles on the financial compensation to be paid in case of curtailment or re-dispatch, thus reducing the additional investment risk linked to losing priority access and thereby reducing any increase in capital costs. In order to ensure effective implementation of the new market rules prior to abolishment of priority dispatch and access, priority dispatch and access may be maintained for an interim period after entry into force of the other measures adressing Problem 1.

Increased transparency and legal certainty on curtailment and re-dispatch are a "no regret" measure, in so far as they contribute to market functioning even in the absence of changes to the priority dispatch and priority access framework. Ensuring sufficient compensation for curtailment, notably for RES E, will increase costs to be borne by system operators. In so far as these costs are currently integrated into renewable subsidy schemes, total system costs will however remain similar. As regards priority grid access, this is the preferred option, in order to ensure that the abolishment of priority grid access has no unwanted negative consequences on the financial framework notably of RES E but also of CHP.

1.1.5. *Comparison of the options*

It should be noted that the removal of priority dispatch and priority access does not equally affect different technologies and generators in different Member States:

- The removal of priority dispatch mostly affects high marginal cost technologies (biomass, indigenous resources, some CHP), as low marginal cost technologies (wind, PV) are generally dispatched when available already on the basis of the merit order. Without priority dispatch, high marginal cost technologies thus take up a role more generally associated with other high marginal cost plants, such as gas-fired power plants, operating only in periods of high prices (high residual load). Those generators are then incentivized to making best use of the inherent flexibility that their technology can provide to a power system, and thus accompany the change to an electricity system with a high share of variable low marginal cost generation. For high marginal cost generation, removal of priority dispatch can significantly reduce the number of running hours. Studies for the Commission have shown a reduction of approximately 85 % in dispatch of wood-based biomass generation, mostly to the benefit of gas-fired power plants[12]. To the contrary, there is a (more limited) increase in the running hours of low marginal cost generation, including wind and solar;

- The reduction in inefficient biomass dispatch would represent a major part of the significant reductions of system costs presented in Figure 1 below, with annual savings of 5.9 billion Euros, expected by the removal of market distortions under Problem Area I, Option (1a) of the impact assessment[13];

Figure 1: Reduction in system costs by abolishment of priority rules

	Baseline	Option 1a
Energy (TWh)	3620	3610
CO2 emissions (Mt)	555	615
Cost day-ahead (B€)	82.5	76.9
Cost intraday (B€)	1.4	0.9
Cost balancing (B€)	- 0.5	- 0.3
Total cost (B€)	83.4	77.5
Savings (B€)	-	5.9
Load payment (B€)	278	293
Average price (€/MWh)	79	83

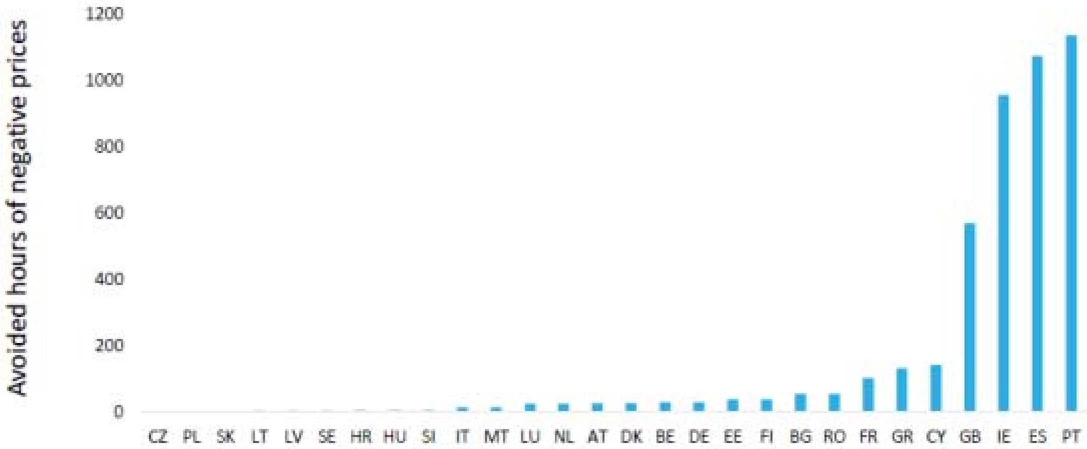
Source: METIS

- By achieving market-based dispatch, the removal of priority dispatch for all technologies drastically reduces the occurrence of negative prices. Whereas negative prices can be a normal occurrence in well-functioning markets which have opportunity costs linked to not offering a service (as is the case on the electricity markets), the occurrence of negative prices based on priority rules shows that priority is given also in times where the system does not require additional generation.

12 For this assessment, biomass was assumed to consist of 22 % "must-run" waste incineration (OPEX: 3.6 EUR EUR/MWh) and 78 % wood-fired plants with high variable costs (around 90 EUR EUR/MWh)

13 For more details please see Section 6.1.2 of the impact assessment.

Figure 2: reduction of negative price occurrences by removal of priority dispatch



Source: METIS

- The removal of priority access on the other hand mostly affects technologies which are producing in areas and at times of network congestion. This will more often concern low marginal cost technologies (especially wind) as periods of high wind feed in are more likely to result in congested network elements, requiring curtailment or re-dispatch;
- Providing clear and transparent rules on curtailment and compensation benefits all market actors. This is particularly true for small and/or new market actors, including RES E;
- While the change of biomass dispatch to reflect its role as flexible back-up generation, to the benefit mostly of gas, but also of coal and nuclear generation thus would drastically reduce future system costs, it could possible entail an increase of CO2 emissions in the power sector, whereas total CO2 emissions under the ETS framework would in principle remain identical over time[14].

Option 1 would be the most effective in achieving the objective of non-discrimination and market efficiency. However, it could result in an increase of costs to achieve other policy objectives, notably for decarbonisation of the energy system. Fully removing priority dispatch and access would also result in an increased need for small generators, including households (e.g. rooftop solar) to participate in the electricity market. While this would allow strong economic incentives, it would thus increase the administrative impact for households and SMEs. Thus, clear and transparent rules for the market participation of RES E and CHP as well as limited exemptions for small and emerging technologies should be included, to accompany the phase-out of priority access and priority dispatch. On the other hand, remaining at the *status quo* would, with a growing share of priority technologies in the system, seriously undermine effective price formation and dispatch in the wholesale market. The preferred option is thus a

[14] The environmental impacts from the removal of priority dispatch for biomass are discussed in Section 6.1.6 of the impact assessment

combination of Options 2 and 3. This will allow a reduction of the administrative impact for households and SMEs while ensuring the most efficient use of bigger mature power generators.

1.1.6. *Subsidiarity*

Priority dispatch is foreseen directly in EU law. Changing or removing those provisions cannot be achieved on a national level. Furthermore, in an integrated electricity market, the way to determine which power plant is operated has a direct impact on cross-border trade. Applying discriminatory provisions for power plant dispatch in certain Member States can thus negatively affect cross-border trade or even directly result in discrimination against power generators in other Member States. Ensuring efficient market integration and functioning investment signals, requires fundamental dispatch rules to be harmonized.

1.1.7. *Stakeholders' opinions*

In the public consultation, most stakeholders support the full integration of Renewable energy sources into the market, e.g. through full balancing obligations for renewables, phasing-out priority dispatch and removing subsidies during negative price periods. Many stakeholders note that the regulatory framework should enable RES E to participate in the market, e.g. by adapting gate closure times and aligning product specifications. A number of respondents also underline the need to support the development of aggregators by removing obstacles for their activity to allow full market participation of renewables.

Also stakeholders from the renewable sector often recognize the need to review the priority dispatch framework. They make this however subject to conditions; Wind Europe provided views on curtailment of wind power and priority dispatch and stated that "*countries with well integrated day-ahead, intraday and balancing market and a good level of interconnections, where priority of dispatch is not granted to CHP and conventional generators, do not need to apply priority of dispatch for wind power."* They argue that "*in general, priority dispatch should be set according to market maturity and liberalisation levels in the Member State concerned, but also taking due account of progress in grid developments and application of best practices in system operation*." According to its paper from June 2016 on curtailment and priority dispatch, in the view of Wind Europe[15], some EU markets, such as Sweden and the UK, which have relatively high penetration rates of wind, do not offer priority dispatch for wind producers[16] and this does not place any restrictions on market growth. However, a phase-out of priority dispatch for renewable energies should only be considered if (i) this is done also for all other forms of power generation, (ii) liquid intraday markets with gate closure near real-time, (iii) balancing markets allow for a competitive participation of wind producers; (short gate closure time, separate up/downwards products, etc.), and (iv) curtailment rules

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15 https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Priority-Dispatch-and-Curtailment.pdf.

16 The Commission services interpret this to mean that, while priority dispatch may be foreseen under national legislation, it has no practical impact.

and congestion management are transparent to all market parties. According to Wind Europe, these requirements are already in 2016 fulfilled in certain markets such as the UK, Sweden and Denmark, whereas other Markets currently still required priority dispatch. It is the view of the Commission services that by entry into force of the present legislative initiative, the above requirements are met in all Member States.

Regarding priority access, Wind Europe asks for curtailments to be valued by the market as a service to ensure system security. It should be treated as downward capacity and its price should be set via the balancing market. This would already be applied in the Danish and UK markets. Participation of wind in the balancing markets could lead to a significant reduction of curtailments. This is taken into account in Option 3, which ensures the primary use of available market-based ressources prior to any non-market based curtailment. Where balancing ressources are available, including from RES E, and capable of adressing the system problem underlying the planned curtailment, they thus have to be used before non-market based curtailment takes place. For this second step, transparent compensation rules are foreseen. Wind Europe recognizes that *"there may be a benefit from not compensating 100% of the opportunity cost. Reducing slightly the income could send an important incentive signal to investors to select locations with existing sufficient network capacity, Curtailment would then be likely to occur less frequently. The exact % of the opportunity cost needs to be carefully assessed in order to find a balance between an increase in policy cost and the increase of financing costs due to higher market risk."* This position is reflected in the present proposal.

Stakeholders from the cogeneration sector underline the link to priority dispatch for renewable energies. COGEN Europe submits that it is "*important that at EU level CHP benefits from at least parity with RES on electricity provisions, as long as there are no additional policy measures that would compensate for the loss in optimal operation ensured through priority of dispatch for certain types of CHPs."* They also argue that "*while a significant fraction of the CHP fleet can be designed and/or retrofitted to operate in a more flexible way (e.g. though partial load capabilities, enhanced design from the electrical components, and the heat storage addition), this may come at the expense of the site efficiency and industrial productivity.*" The parallelism to RES is maintained in all options, whereas the additional costs and possible loss of efficiency have to be balanced with the economic cost of significant amounts of inflexible conventional generation in a high-RES system.

EUROBAT, association of European Manufacturers of automotive, industrial and energy storage batteries, regards curtailing of energy as a system failure, as the "wasted" power should be stored in batteries instead. It argues against any financial compensation to renewable generators for being curtailed, as such a compensation would disincentivize the installation of energy storage systems[17].

Transmission system operators would be directly affected, as they are responsible for practical implementation of the priority rules. In May 2016, ENTSO-E has asked their Members to provide answers to questions which had been discussed with the

[17] http://www.eurobat.org/sites/default/files/eurobat_batteryenergystorage_web.pdf p.28.

Commission services. 29 TSOs from 25 countries have replied, though not all TSOs answered all questions, which is also due to the limited impact of priority dispatch/access in some Member States (with a low share of CHP and RES E). TSOs from 14 Member States answered that priority dispatch increases the costs of pursuing stable, secure and reliable system operations. TSOs from a smaller group of Member States (4 to 6) also stated that priority dispatch limits the possibilities to keep the grid stable, secure and reliable. Only the TSOs of three Member States answered that priority dispatch has no major effect on system operations. Regarding the market impact, TSOs from 12 Member States raised increased dispatching costs and 9 raised the occurrence of negative prices. On the other hand, TSOs from one Member State argued that priority dispatch resulted in reduced costs for the support of RES E. TSOs also stressed the cross-border impact of priority dispatch: TSOs from 6 Member States referred to increased congestion of interconnectors, and an example provided was that priority dispatch in neighbouring areas impacted the system operation in the TSOs area. When asked how European legislation should adress the issues mentioned, no TSO wanted to retain priority dispatch, 8 TSOs wanted to retain it with exemptions, 4 TSOs wanted a phase out of priority dispatch, and 13 TSOs wanted priority dispatch to be removed entirely.

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Priority access and dispatch

1.2. Regulatory exemptions from balancing responsibility

1.2.1. *Summary table*

Objective: To ensure that all technologies can compete on an equal footing, eliminating provisions which create market distortions unless clear necessity is demonstrated, thus ensuring that the most efficient option for meeting the policy objectives is found. Each entity selling electricity on the market should be responsible for imbalances caused.

	Option 0	Option 1	Option 2	Option 3
Description	Do nothing. This would maintain the *status quo*, expressly requiring financial balancing responsibility only under the State aid guidelines which allow for some exceptions.	Full balancing responsibility for all parties Each entity selling electricity on the market has to be a balancing responsible party and pay for imbalances caused.	Balancing responsibility with exemption possibilities for emerging technologies and/or small installations This would build on the EEAG.	Balancing responsibility, but possibility to delegate This would allow market parties to delegate the balancing responsibility to third parties. This option can be combined with the other options.
Pros	Lowest political resistance	Costs get allocated to those causing them. By creating incentives to be balanced, system stability is increased and the need for reserves and TSO interventions gets reduced. Incentives to improve e.g. weather forecasts are created.	This could allow shielding emerging technologies or small installations from the technical and administrative effort and financial risk related to balancing responsibility.	The impact of this option would depend on the scope and conditions of this delegation. A delegation on the basis of private agreements, with full financial compensation to the party accepting the balancing responsibility (e.g. an aggregator) generally keeps incentives intact.
Cons		Financial risks resulting from the operation of variable power generation (notably wind and solar power) are increased.	Shielding from balancing responsibilities creates serious concerns that wrong incentives reduce system stability and endanger market functioning. It can increase reserve needs, the costs of which are partly socialized. This is particularly relevant if those exemptions cover a significant part of the market (e.g. a high number of small RES E generators).	The impact of this option would depend on the scope and conditions of this delegation. A full and non-compensated delegation of risks e.g. to a regulated entity or the incumbent effectively eliminates the necessary incentives. Delegation to the incumbent also results in further increases to market dominance.

Most suitable option(s): Option 2 combined with the possibility for delegation based on freely negotiated agreements.

1.2.2. *Description of the baseline*

Balancing responsibility refers to the obligation of market actors (notably power generators, demand response providers, suppliers, traders and aggregators) to deliver/consumer exactly as much power as the sum of what they have sold and/or purchased on the electricity market. Predictions for demand and (to a more limited extent) generation being not 100 % precise, market actors are often not fully balanced. The Transmission System Operator then ensures that total demand and supply are maintained in balance by activating (upward or downward) balancing energy, often coming from dedicated balancing capacities.

Balancing responsibility implies that the costs of the balancing actions taken by the transmission system operator are generally to be compensated by the market parties which are in imbalance. In some Member States, certain types of power generation (notably wind and solar, but possibly also other technologies such as biomass) are excluded from this obligation or have a differentiated treatment. Most Member States foresee some degree of balancing responsibility also for renewable generators; based on an EWEA (now Wind Europe) study, in 14 out of 18 Member States with a wind power share above 2-3 % in annual generation, wind generators had some form of balancing responsibility[18]. This however does not always translate into real financial responsibility of the generator for imbalances it caused. In Austria for example, a public entity, OEMAG, acts as balancing responsible party for all subzidized renewable generation, thus shielding individual generators from imbalance risks of their power plants[19] and collectively purchasing/selling balancing energy for the renewable sector[20]. On the other hand, in a small number of Member States balancing costs imposed on renewable power generation can be prohibitively high and almost reach the level of wholesale prices (e.g. incurred balancing costs of up to 24 EUR/MWh in Bulgaria and 8-10 EUR/MWh in Romania)[21].

Article 28 (2) of the Balancing Guideline provides that *"each balance responsible party shall be financially responsible for the imbalance to be settled with the connecting TSO"*. This does not, however, preclude frameworks in which market actors are (fully or partly) shielded from the financial consequences of imbalances caused by having this responsibility shifted to another entity. This is part of some current support schemes.

The EEAG provide that in order for State aid to be justified, RES E generators need to bear full balancing responsibility unless no liquid intra-day market exists. The EEAG rules however do not apply where no liquid intraday market exists, and and also do not apply to installations with an installed electricity capacity of less than 500 kW or

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18 http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA-position-paper-balancing-responsibility-and-costs.pdf, p. 5-6.

19 https://www.energy-community.org/portal/page/portal/ENC_HOME/DOCS/2014187/0633975ACF8E7B9CE053C92FA8C06338.PDF

20 http://www.oem-ag.at/de/oekostromneu/ausgleichsenergie/.

21 http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA-position-paper-balancing-responsibility-and-costs.pdf p. 8.

demonstration projects, except for electricity from wind energy where an installed electricity capacity of 3 MW or 3 generation units applies. The exemption from balancing responsibility in the absence of liquid intra-day markets is based on the reasoning that were liquid intra-day markets *do* exist, they allow renewable generators to drastically reduce their imbalances by trading electricity on short-term markets and thus taking account of updated wheather forecasts. This shows that imposition of balancing responsibility is thus closely linked to the creation of liquid short-term markets, one of the main objectives of the electricity market design initiative.

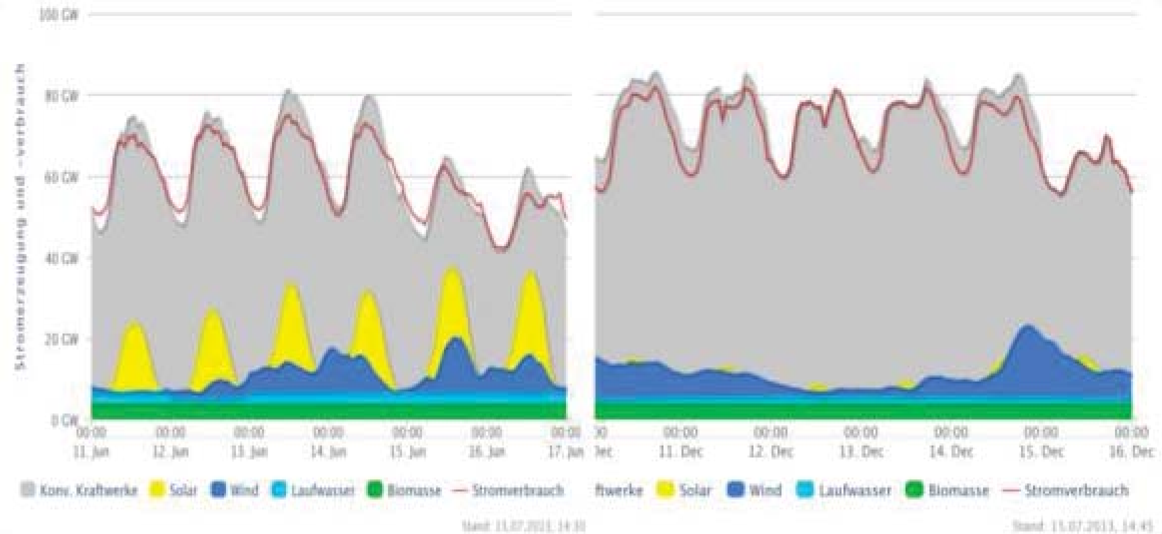
The corollary to balancing responsibility is the possibility to participate in the balancing market, offering balancing capacity to the TSO against remuneration. This is further described under Section 5.1.1.4 and closely linked to the Balancing Guideline.

1.2.3. *Deficiencies of the current legislation*

Already today, the increased share of renewable energies in power generation (approximately 29% in 2015) has significant impact on market functioning and grid operation. This effect is most noticeable in Member States with RES E shares above the EU average.

The below figure shows two relevant weeks, with production and consumption shown together. In the left graph, generation exceeds the load (red line) in situation with lots of solar power generation (yellow). In the right graph, less renewable power is generated (blue, green, yellow, but minimal PV (yellow)). Supply and demand of electricity has to match at all times despite changes in demand and variable renewable electricity production. For both situations, flexibility options such as storage, demand side response, flexible generation and interconnection import/export capacities are needed to take up electricity.

Figure 1: Volatility in the German power market in June and December 2013



Source: Agora Energiewende 2013.

To integrate renewable production progressively and efficiently into a market that promotes competitive renewables and drives innovation, energy markets and grids have to be fit for renewables. This is not necessarily the case in many jurisdictions since markets have traditionally been designed to cater the needs of conventional generation rather than variable renewables. To make markets fit for renewables means developing adequately the short-term markets such as intraday and balancing. This also means allowing, to the maximum possible extent, renewables to participate in all electricity markets on equal footing to conventional generation removing all existing barriers for renewable energy sources integration. Integrating RES E into the market and allowing them to generate a large part of their revenues from market prices requires an increase of flexibility in the system, which is also needed for absorbing cheap renewable electricity at times of high supply. It is for this reason that the EEAG (para.124) requires generators to be subject to standard balancing responsibilities only unless no liquid intra-day market exists. Liquid intra-day markets should exist in all Member States at the expected date of entry into force of the revised legislation, accompanying the present impact assessment. However, the term "liquid intra-day market" allows significant margin of interpretation and can thus cause uncertainty on the application of one of the fundamental rules on the electricity market. It will be necessary to further clarify this exemption and ensure that market actors have legal certainty as to whether they have to bear balancing responsibility or not.

Investment incentives should take into account the value of generation at different times of the day or of the year. Progress has been made in this area, with support schemes relying increasingly (but not everywhere or for all generation) on premiums instead of fixed feed-in tariffs. Where premium-based support schemes are used, the degree of market exposure depends on their exact implementation, differing e.g. between fixed and floating premium models, and for the latter relative to the determination of the base price used for the calculation of the premium. Full exposure to market signals may e.g. make a different generation installation more efficient although it produces lower total output (such as orienting PV to the west to increase output later in the day). By exposing generators to the financial consequences of imbalances caused, the incentives given to generators do not relate only to optimizing the expected generation of their power plant in view of market needs, but also to ensuring that the electricity they sell on the market matches as closely as possible the power produced at a certain point in time. In a questionnaire to TSOs organized by ENTSO-E, the example was given that following the attribution of balancing responsibility in a Member State, the average hourly imbalance of PV installations improved from 11.2 % in 2010 to 7.0 % in March 2016, and the average hourly imbalance of wind improved from 11.1 % to 7.4 % over the same period.

Where RES E generators do not assume balance responsibility identical to other generators and participate in the balancing market, they lack incentives for efficient operational and investment decisions[22]. Part of this challenge is the need to avoid inacceptable risks for RES E investors by imposing balance responsibilities without

[22] KEMA study commissioned for the EU Commission (ENER/C1/427-2010, Final report of 12 June 2014), p.185

creating the market flexibility which allows staying balanced[23]. Whereas many Member States already foresee some balancing responsibility for RES E generators (2013: 16 Member States)[24] this is not yet the case for all Member States, and the degree of balancing responsibility differs considerably between Member States. This can result in market distortions, directing investments to Member States with lower degree of responsibility rather than to those Member States where electricity demand and renewable generation potential are optimal, and can also result in lower liquidity of short-term markets.

Reduced balancing responsibility can also result in increasing imbalances in electricity trades. Whereas the TSO will generally, via the balancing market, be capable of covering imbalances, a high degree of imbalances reduces predictability of system operation and can increase system stress (e.g. by reducing the volume of available reserves) or increase costs for system stability (e.g. if higher reserve volumes are procured in advance).

Finally, it should be noted that the EEAG already foresees the need to phase out exemptions from balancing responsibilities in the post-2020 period[25]. The EEAG itself provides in its paragraph 108 that the Guidelines *"apply to the period up to 2020 but should prepare the ground for achieving the objectives set in the 2030 framework, implying that subsidies and exemptions from balancing responsibilities should be phased out in a degressive way"*.

Refrence is also made to Section 7.4.2 of the evaluation.

1.2.4. <u>*Presentation of the options*</u>

Balancing responsibility of all market parties active on the electricity market is a fundamental principle of EU energy law. This principle should not be included only in a State aid guideline and in the Balancing Guideline but ensured at the level of secondary law, thus increasing transparency and legal certainty. Exemptions currently foreseen in the guidelines need to be reassessed and, where still necessary, further clarified. It should also be further clarified in how far and under which conditions delegation of this responsibility is possible. It is thus proposed to establish a general rule that all market-related entities or their chosen representatives shall be financially responsible for their imbalances, and that any such delegation/representation shall not entail a disruption of incentives for market parties to remain balanced. Provisions in this direction are already included in the Balancing Guideline which will be discussed in Comitology in the second

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[23] KEMA p. 185: *"Experience from some EU countries has shown that RES generators are able to provide less volatile and more predictable generation schedules if so incentivized by balancing arrangements."*

[24] http://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd04_en.pdf Appendix I table 6.

[25] Paragraph 108 EEAG reads: "*These Guidelines apply to the period up to 2020. However, they should prepare the ground for achieving the objectives set in the 2030 Framework. Notably, it is expected that in the period between 2020 and 2030 established renewable energy sources will become grid-competitive, implying that subsidies and exemptions from balancing responsibilities should be phased out in a degressive way. These Guidelines are consistent with that objective and will ensure the transition to a cost-effective delivery through market-based mechanisms.*"

half of 2016. General principles and, where applicable, exemptions shall be integrated into the Electricity Directive for added clarity and legal certainty.

Option 0: do nothing

This would mean that balancing responsibility remains subject only to State aid rules and the rules in the Balancing Guideline. Fundamental principles of electricity market operation should systematically not be decided upon only in acts adopted under the Comitology process and guidelines which undergo no legislative process. Furthermore, the EEAG are limited in time to 2020 and uncertainty as to the extent of their exemptions and their applicability post-2020 will persist. According to their paragraph 108, it is expected that in the period between 2020 and 2030 established renewable energy sources will become grid-competitive, implying that subsidies and exemptions from balancing responsibilities should be phased out in a progressive way (and thus assuming liquid short-term markets to develop). Finally The State aid guidelines only apply to those parts of measures which are to be seen as State aid. This concerns most, but not necessarily all, generation which may not be fully balancing responsible. For some aspects the qualification as State aid could potentially be put into question.

Option 0+: Non-regulatory approach

As national law is extremely varied to date, without a clear and transparent framework setting out the degree of balancing responsibility, enforcement of existing rules (e.g. State aid rules) is unlikely to result in a uniform and non-discriminatory legal framework.

Voluntary cooperation can contribute to reducing the negative impact of imbalances. Imbalance netting by transmission system operators already achieves significant cost reductions. However, voluntary cooperation does not provide sufficient legal certainty and the minimum degree of harmonization to avoid distortions in cross-border trade. In fact, shielding certain market parties fully or in part from balancing responsibilities creates economic advantages which can distort cross-border trade in electricity. Where a lack of balancing responsibility results in increased imbalances, this will negatively impact the whole synchronous area, and thus create costs and risks for system stability also in other Member States.

Option 1: Full Balancing responsibility for all parties

This would entail that the principles of the Balancing Guideline imposing all market-related entities and their representatives to be financially responsible for imbalances caused would be integrated into the Electricity Directive.

This option would thus significantly increase transparency and legal certainty. Balancing responsibility is already an accepted concept under the EEAG, so that the market impact would be limited to those entities currently benefitting from exemptions or not subject to State aid rules. While this option would optimally achieve the defined objective, the complete abolishment of the existing exemptions could result in increased administrative effort for small installations or demonstration projects using emerging technologies.

Option 2: Balancing responsibility with exemption possibilities for emerging technologies and/or small installations

This would allow Member States to foresee that certain emerging technologies and/or small installations (e.g. rooftop solar) are shielded from the direct financial impact of imbalances they cause. As imbalances need to be covered by some entity, this could be achieved by allocating it to public bodies (essentially meaning that these entities are acting as sellers of RES E on the wholesale market), the costs of which are then socialized.

This option addresses the currently existing exemptions under EEAG, based on the assumption that short-term markets have developed sufficiently by the time of entry into force of the proposed legislation to require balancing responsibility of generators not covered by the exemptions. Without introducing additional limitations, these exemptions would however risk reducing effectiveness in achieving the policy objective. This is notably the case for small installations, which under some scenarios can account for a significant part of total electricity supply.

Option 3: Possibility to delegate balancing responsibility

This option would entail the right to delegate balancing responsibilities to a third party. Whereas the freely negotiated delegation to a third party against financial compensation (e.g. an aggregator) can reduce administrative impact without reducing the incentive to reduce imbalances (as their cost will be passed on to the generator in some way), regulated delegations without compensation drastically reduce or eliminate the incentive to remain balanced.

The possibility to delegate on the basis of free negotiation, against financial compensation, (combined with exemptions notably for demonstration projects and possibly very small installations) is the preferred option. It fully achieves the policy objectives, and allows notably smaller installations to reduce administrative efforts without reducing market incentives.

1.2.5. *Comparison of the options*

The requirement of full balancing responsibility does not affect all renewable technologies in the same manner. Biomass and other non-variable technologies are generally capable of being balanced to the same degree as conventional generators. Variable generators (especially wind and PV) can increasingly predict their generation based on wheather forecasts, but have a higher margin of error in those predictions than conventional generators. To reduce the margin of error, those technologies need to improve wheather forecasts, as well as sell electricity for shorter time periods in advance, when better forecasts become available.

A study using METIS has shown very significant reductions in frequency restoration reserve needs due to the introduction of balancing responsibilities for RES E. Whereas FCR and aFRR needs relate to short-term frequency deviations and are thus not significantly affected by balancing responsibility, mFRR needs are based on longer-lasting deviations from indicated schedules. By creating incentives for improved forecasts and more exact schedules, reserve needs are thus significantly reduced.

Figure 2: reduction in reserve needs depending on balancing responsibility

GW		Baseline	Option 1a
FCR + aFRR	Upwards	16.7	16.7
	Downwards	16.2	16.1
mFRR	Upwards	23.5	17.4
	Downwards	23.2	15.6
Total (FCR + FRR)		**79.6**	**65.8**
Reduction		**-**	**17%**

Important impact on mFRR needs (-30%)

Source: METIS

Option 1 would be most effective at achieving the objective of well-functioning markets. All exemptions from balancing responsibility, even if only partly shielding against the financial impact of imbalances, reduce the incentive to be balanced. The complete abolishment of the existing exemptions would however result in increased administrative effort for small installations or demonstration projects using emerging technologies. This could slow down roll-out of new RES E technologies and could thus render the achievement of the decarbonisation objective more costly. Options 2 and 3 can be combined to ensure a maximum degree of balancing responsibility with the potential to delegate this responsibility, which allows reduction of the additional administrative impact imposed especially on small installations. This being said, small installations are currently often not active on the market, and it could be excessive to require balancing responsibility even taking into account the possibility to delegate. The preferred option is thus a derogation from balancing responsibilities for demonstration projects and small generation (e.g. rooftop solar), and the right for other projects to delegate their balancing responsibility against financial compensation. This significantly reduces the administrative effort for households and small and medium enterprises (who will often continue to benefit from exemptions from balancing responsibilities) but takes account of the increased role renewable generation plays in the market, and the improved capabilities particularly of larger generators to predict their output and reduce or hedge remaining imbalance risks.

1.2.6. <u>*Subsidiarity*</u>

Balancing responsibility is a fundamental principle in every electricity market. It ensures that market agreements are also reflected in the physical reality, and that the costs of imbalances created are born by those creating them. Balancing responsibiltity impacts both investment decisions and trading on electricity markets; every decision to sell electricity on the market entails the risk to be in imbalance, which thus has to be integrated into bidding strategies. Deviations on a national level in an integrated market could result in distortions of cross-border trade, e.g. by making investments into variable generation in one Member State significantly more interesting than in other Member States, and basic principles for balancing responsibility thus need to be harmonized.

Furthermore, increasing the share of RES E in the total energy consumption is an EU target. For 2030, a target binding at EU level exists, without nationally binding targets; therefore the EU has to ensure the EU target is reached. With an increasing share of RES E, they become a relevant player on the power markets. As power markets are increasingly integrated, this has direct cross-border impact. Equal treatment to all generation technologies should be ensured to avoid market distortions. Markets should be fit to allow all generation technologies and demand to compete on equal footing, while allowing the EU to reach the policy objectives of sustainability, competitiveness and security of supply. The increasing share of RES E also creates challenges for network operation. In synchronous areas even exceeding the EU, this is an issue which cannot be resolved at national level alone.

1.2.7. *Stakeholders' opinions*

In the public consultation, most stakeholders support the full integration of renewable energy sources into the market, e.g. through full balancing obligations for renewables, phasing-out priority dispatch and removing subsidies during negative price periods. Many stakeholders note that the regulatory framework should enable RES E to participate in the market, e.g. by adapting gate closure times and aligning product specifications. A number of respondents also underline the need to support the development of aggregators by removing obstacles for their activity to allow full market participation of renewables. The approach chosen in the State aid guidelines found broad support by most stakeholders.

Wind Europe's predecessor EWEA submitted[26] that in 14 out of 18 Member States, wind generators were already balancing responsible in financial or legal terms, generally subject to the same rules as conventional generation. However, in some Member States, balancing costs for renewable generators appeared discriminatorily high. Important considerations for wind generators to accept balancing responsibility were, for EWEA: (i) the existence of a functioning intra-day and balancing market, (ii) balancing market arrangements providing for the participation of wind power generators, as e.g. shorter gate closure time and procurement timeframes, (iii) market mechanisms that properly value the provision of non-frequency ancillary services for all market participants including wind power, (iv) a satisfactory level of market transparency and proper market monitoring, (v) sophisticated forecast methods in place in the power system and (vi) the necessary transmission infrastructure. While forecast methods should be developed by the market and cannot be provided directly in policy (which can only give incentives for

26 http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA-position-paper-balancing-responsibility-and-costs.pdf

such methods to be improved and used), the market design initiative aims at achieving all these points.

In its consultation of national TSOs, ENTSO-E also adressed questions on balancing responsibility. TSOs in five Member States answered that after introduction of balancing responsibilities, RES E generators were more motivated to conclude energy production contracts which are close to the real production in each market time unit; for four Member States, better forecasts were used by RES E generators. 1 TSO provided figures according to which the average hourly imbalance of PV installations improved from 11.2 % in 2010 to 7.0 % in March 2016, and the average hourly imbalance of wind improved from 11.1 % to 7.4 % over the same period.

1.3. RES E access to provision of non-frequency ancillary services

1.3.1. *Summary table*

Objective: transparent, non-discriminatory and market based framework for non-frequency ancillary services		
Option 0	**Option 1**	**Option 2**
BAU Different requirements, awarding procedures and remuneration schemes are currently used across Member States. Rules and procedures are often tailored to conventional generators and do not always abide to transparency, non-discrimination. However increased penetration of RES displaces conventional generation and reduces the supply of these services.	Description Set out EU rules for a transparent, non-discriminatory and market based framework to the provision of non-frequency ancillary services that allows different market players /technology providers to compete on a level playing field.	Description Set out broad guidelines and principles for Member States for the adoption of transparent, non-discriminatory and market based framework to the provision of non-frequency ancillary services.
Stronger enforcement Provisions containing reference to transparency, non-discrimination are contained in the Third Package. However, there is nothing specific to the context of non-frequency ancillary services.	Pro Accelerate adoption in Member States of provisions that facilitate the participation of RES E to ancillary services as technical capabilities of RES E and other new technologies is available, main hurdle is regulatory framework. Clear regulatory landscape can trigger new revenue streams and business models for generation assets.	Pro Sets the general direction and boundaries for Member States without being too prescriptive. Allows gradual phase-in of services based on local/regional needs and best practices.
	Con Resistance from Member States and national authorities/operators due to the local/regional character of non-frequency ancillary services provided. Little previous experience of best practices and unclear how to monitor these services at DSO level where most RES E is connected.	Con Possibility of uneven regulatory and therefore market developments depending on how fast Member States act. This creates uncertain prospects for businesses slowing down RES E penetration.
Most suitable option(s): Option 2 is best suited at the current stage of development of the internal electricity market. Ancillary services are currently procured and sometimes used in very different manners in different Member States, Furthermore, new services are being developped and new market actors (e.g. batteries) are quickly developing. Setting out detailed rules required for full harmonisation would thus preclude unknown future developments in this area, which currently is subject to almost no harmonisation.		

1.3.2. *Description of the baseline*

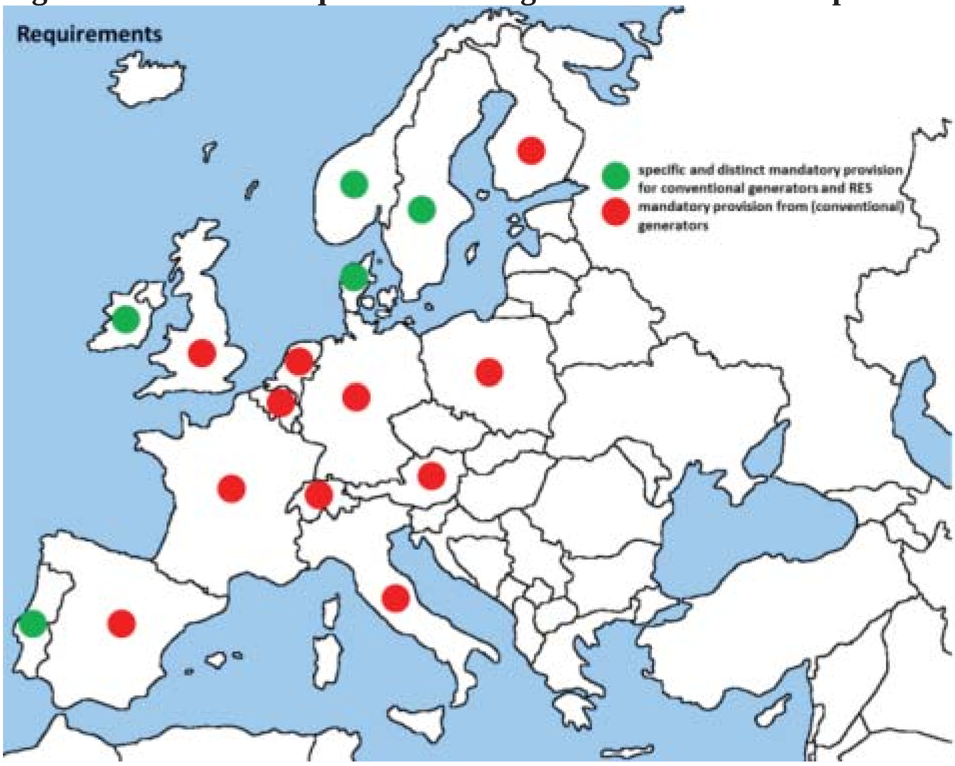
The delivery of **frequency** related ancillary services by RES E assets is partly covered by the Balancing Guideline.

Non-frequency ancillary services are services procured or mandated by TSOs that support the electricity network, such as voltage support, short circuit power, black start capability, synthetic inertia or congestion management. They are in most cases supplied by electricity generators, but can in some cases also be supplied by demand facilities, electricity storage or network equipment.

Currently, the procurement of non-frequency anciliary services is not regulated at EU-level. The situation in Member States for the provision of **non-**frequency ancillary services is determined by national grid codes that *inter alia* specify the rules for connection of generation assets to the electric network infrastructure. Grid codes are evolving continuously, but a snapshot taken recently through studies funded by the European Commission[27], a survey commissioned by ENTSO-E[28] and by examining the actual national grid codes, reveals that several approaches are considered in Europe across more than a dozen Member States (as well as Norway and Switzerland) surveyed. The snapshot, summarized in Figures 1 to 3, focuses only on the provision of reactive power, i.e. voltage related ancillary services, one of the most important non-frequency ancillary services. It is important to point out that the overview is partial and does not cover all specific arrangements TSOs might have. For instance in Denmark, these services are not generally remunerated, however in certain periods of the year when thermal plants are not operating, these services are remunerated to guarantee sufficient supply.

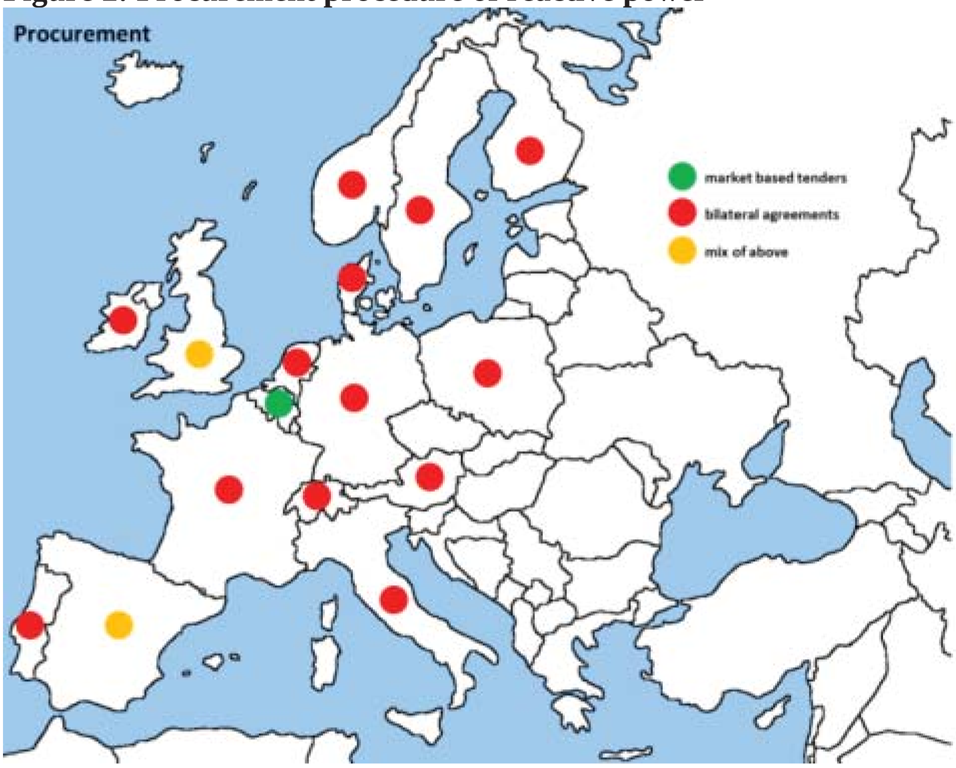
27 *"REserviceS project"* (2014) Intelligent Energy Europe programme, http://www.reservices-project.eu/
28 *"Survey on Ancillary Services Procurement and Electricity Balancing Market Design"* (2015) ENTSO-E, https://www.entsoe.eu/Documents/Publications/Market%20Committee%20publications/WGAS%20Survey_04.05.2016_final_publication_v2.pdf?Web=1

Figure 1: Grid code requirements for generators on reactive power



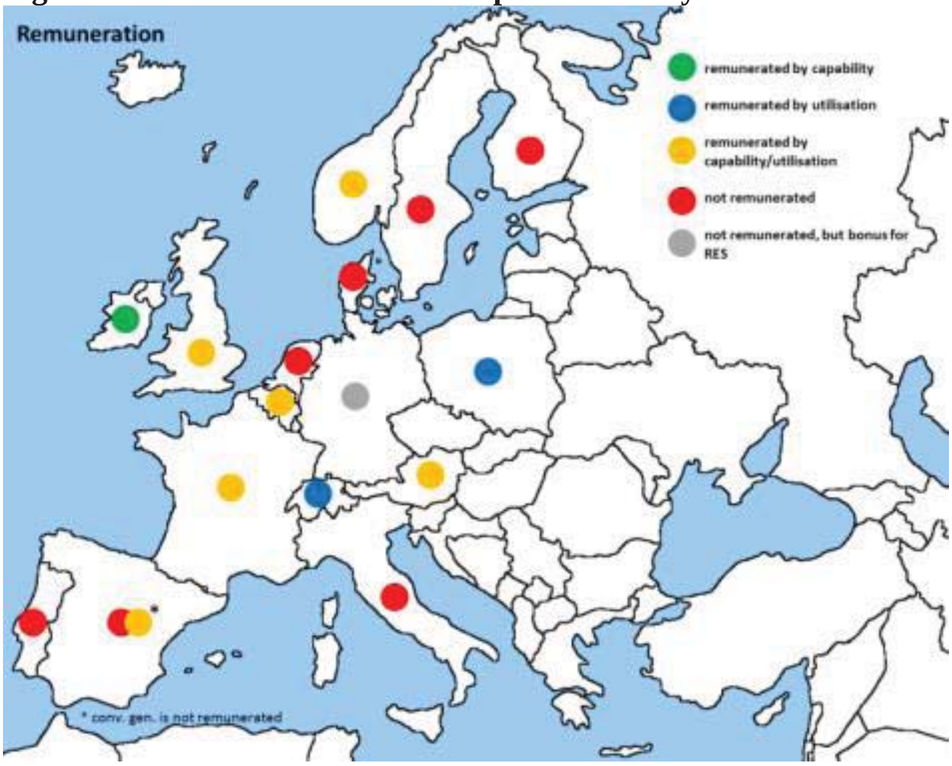
Source: National grid codes, ENTSO-E survey, REserviceS project

Figure 2: Procurement procedure of reactive power



Source: National grid codes, ENTSO-E survey, REserviceS project

Figure 3: Remuneration of reactive power delivery



Source: National grid codes, ENTSO-E survey, REserviceS project

Currently the practises with regard to requirements, procurement and renumeration of non-frequency anciliary services can be summarised as follows:

- Requirements: most Member States demand mandatory provision from conventional generators and in some cases specific provisions are considered for RES E, mostly wind. The latter approach is in line with the Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators ('RfG');
- Procurement: a majority of Member States procure these services through bilateral agreements and only in a small minority of Member States market based tenders are used. In other Member States both bilateral agreements and market based tenders are used;
- Remuneration: about half of the surveyed Member States do not have a mechanism to remunerate the service, the other half does remunerate them either by capability, utilisation or a combination of both. In some Member States, a bonus is given to RES E for upgrading the infrastructure.

1.3.3. *Deficiencies of the current legislation*

The current EU regulatory framework defines in Article 12 lit. d) of the Electricity Directive the role of the TSO: it includes ensuring the availability of all necessary ancillary services. However, there is nothing specific with regard to non-frequency ancillary services. The RfG specifies extensively requirements for the provision of reactive power by different power modules. However, it does neither address the procedures by which such services should be awarded (e.g; a market based mechanism), nor whether they should be remunerated (as such or on the basis of what criteria e.g. capacity, utilisation or a combination thereof). Additionally, the RfG is not likely to lead to an efficient deployment of reactive power capability on the territory as voltage support

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services have a geographical dimension and need to be provided in specific locations. This might lead to an oversupply of reactive power capability (with associated increased costs born by the generators) and at the same time underutilization of installed capability because they are not suitably located. The System Operation Guideline aims at ensuring that TSOs use market-based mechanisms as far as possible to ensure network security and stability, but does not articulate further this high level principle.

The current legislation is insufficient and needs to be adapted to trends observed in the market where studies project that the demand for non-frequency ancillary services across Europe will increase over the coming decades, mainly because of increased RES E penetration. A technical and economical study by Électricité de France (EDF)[29] concluded that *"it is essential that variable RES production which is displacing conventional generation is also able to contribute to the provision of ancillary services and also potentially provide new services (e.g. inertia)"*. A study commissioned by the German Energy Agency Dena[30] found that *"due to increasing transport distances and international power transit, the demand for reactive power in the transmission grid will increase significantly by 2030."*

1.3.4. *Presentation of the options*

Option 0 - BAU

In a business-as-usual scenario, non-frequency ancillary services are mainly provided by large conventional generators. Although those services are currently not remunerated in all Member States, TSOs would need those generators to run even if not profitable. Therefore such generators would request additional revenues. This scenario prevent the access to additional revenue streams for new types of generation assets, mainly being RES E.

Since RES E are displacing conventional generation assets, the supply of these services is becoming scarcer. As a result, generation from RES E would be curtailed at certain times to guarantee the safe operation of the electric network. This would likely slow down the deployment of RES E and affect negatively the achievement of the European wide renewable energy consumption targets by 2020 and 2030 and related climate goals.

Option 0+: Non-regulatory approach.

The Third Package does not address the provision of non-frequency ancillary services in a way that could be used to enforce existing legislation stronger. Voluntary cooperation does not provide the necessary minimum degree of harmonization and legal certainty to allow for efficient cross-border trade. Even where non-frequency anciliary services have to be provided on a local level, the provision of and revenues from these services can

[29] *"Technical and Economic analysis of the European Electricity System with 60% RES"* (2015) Alain Burtin & Vera Silva, http://www.energypost.eu/wp-content/uploads/2015/06/EDF-study-for-download-on-EP.pdf

[30] *"Dena Ancillary Services Study 2030"* (2014) German Energy Agency, http://www.dena.de/en/projects/energy-systems/dena-ancillary-services-study-2030.html

have a significant impact on the competitiveness of electricity generation, which competes cross-border.

Option 1 - EU rules setting out a framework for a transparent, non-discriminatory, market based framework

This option would imply setting EU wide harmonized rules in EU legislation on requirements of generators for connection to the grid, on specifications and procurements of products to ensure a level-playing field and fair remuneration of these services. This would encounter a number of issues: even though the provision of non-frequency ancillary services is necessary to run a European wide electricity market, due to the local/regional character of these services, optimal solutions may vary across Member States. Additionally, it would require the coordination of both transmission and distribution system operators as a large fraction of RES E is installed at the distribution level. These services are not generally remunerated at lower voltage levels and no clear framework is yet available on how to regulate these services. Finally, there are still significant challenges for market based integration of ancillary services from RES E due to limitations of predictability of energy output.

Option 2 - Guidelines setting out the principles for the adoption of a transparent, non-discriminatory, market based framework.

The aim is to provide a sound basis for the development of a non-discriminatory, transparent and market based access to non-frequency ancillary services by RES E and to allow the gradual phase-in of services based on local/regional needs and best practices. This is a pre-requisite for a cost efficient allocation of resources to provide the necessary supply of non-frequency ancillary services. The measures should be articulated along the following main lines:

- ensure that the regulatory requirements for the provision of these services are rational with respect to the expected needs (both in terms of quantity and location) and non-discriminatory with respect to different assets capable of providing the service.
- bring transparency to the way ancillary services are procured, for instance through market-based tenders or auctions and allow sufficient flexibility in the process to accommodate bids from assets with different technical characteristics;
- promote mechanisms for remuneration by system operators;
- consult stakeholders when establishing new rules to make sure all assets can participate to these services while providing support for safe grid operation.

These measures are also conducive to a higher penetration of RES E in the electricity network and could be further developed in a dedicated network code.

1.3.5. *Comparison of the options*

The BAU scenario would not be effective in designing a level-playing field for a non-discriminatory, transparent and market based access to non-frequency ancillary services and in achieving the objectives of increasingly integrated RES E in a European electricity market. It would also be an obstacle for further increase of RES E in the generation mix with a potential negative impact on the achievement of the 2030 targets. In the current situation, where ancillary services are provided by conventional generators, curtailment of RES E is required at times to assure the availability of generation assets capable of providing ancillary services (so-called "must run"). The decision to keep these resources online is not based on economic assessments, but only on operational considerations for a safe operation of the grid. Such constraint would not exist or not to the same extent if RES E resources would be used to their fullest potential to provide non-frequency ancillary services.

Options 1 and 2 would be more effective in providing a non-discriminatory, transparent and market-based environment for RES E and new technologies to offer and compete for the provision of non-frequency ancillary services. Companies, especially owners of RES E assets would benefit from additional revenue streams from ancillary markets. Extrapolating the European wide market size for non-frequency ancillary services from national markets (typically in the range of tens of millions of euros) puts it roughly in the range of a few billion euros.

In addition, the investment outlook for additional power plants would be better for owners of RES E assets. Taking Ireland as a best practice case, regulators and TSOs are redesigning the ancillary service market in such a way that RES E can participate. It requires introducing new services and allowing these services to be remunerated. This has the additional benefit that the electricity generation share of RES E in such a redesigned market can be higher without compromising the safe operation of the grid and allows system operators to make efficiency gains: the Irish All Island TSOs compared the estimated costs of enhancing the operational capabilities of ancillary services with the benefits of lower market prices coming from a larger share of wind energy generation. They concluded that the benefit outwheighted the costs already at System Non-Synchronous Penetration levels below 50%[31].

Based on the studies and sources mentioned in this and other Sections of this annexe, little uncertainty exists about the benefits of more transparent provision of ancillary services, one where RES E could participate. For certain services, especially those that have a limited geographical scope, it is unclear if and how liquid markets could be established, with regulated cost+ payments being a possible alternative.

The second Option is preferred over the first one, because at this moment there is not enough evidence to support European wide harmonized rules for non-frequency ancillary services. New services are being developed and new market players are emerging. The first option could preclude unknown future developments in this area, whereas the second option allows the gradual phase-in of services based on local/regional needs and best practices.

1.3.6. *Subsidiarity*

Even though non-frequency anciliary services, such as voltage related ancillary services have a local character, it does not prevent action through the market design initiative. The efficient provision of these services is a critical enabler of an integrated European

[31] *"Onshore wind supporting the Irish grid"* (2013) Andrej Gubina, http://www.reservices-project.eu/wp-content/uploads/D5.1-REserviceS-Ireland-case-study-Final.pdf

electricity market and of higher RES E penetration. Also, the assets that provide non-frequency ancillary services are largely the same ones providing frequency-related services: a local problem due to voltage stability could have implications for the provision of frequency-related services and the stability of the grid at a European level as a whole. Finally, the assets providing ancillary services are generally competing in other markets with a larger geographical scope, including the day ahead and intraday electricity markets. Conditions on voltage control thus have an impact on cross-border competition in electricity markets.

1.3.7. *Stakeholders' opinions*

RES E[32] and demand response[33] industry associations and owners of storage[34] assets assert the technical availability to provide non-frequency ancillary services, but expose difficulties accessing the market because of non-transparent rules for contracting, minimum product size and other product specifications, as well as procurement lead times. Younicos, a storage provider, states that *"storage is not defined in regulatory framework on national or EU level, creating uncertainty on market access and creating uncertainty on ownership roles."* Similarly, the Association of European Manufacturers of automotive, industrial and energy storage batteries (EUROBAT), calls for a legislative definition of storage which allows system operators to own and operate battery storage. The association calls for the value of services offered by storage systems, including voltage control, frequency control and ramp control, to be financially recognized. Anciliary services should thus be compensated[35]. The European Wind Energy Association points out that the reactive power requirements at low active power set points imposed on RES E in the frame of the RfG code could potentially have a substantial negative impact on the investment costs of new wind power plants..

Energinet.dk considers increased competition for the supply of ancillary services *"as a part of the continuous development of the energy only market with the objective to create clear price signals and creating socio economic benefits and security of supply on short and long run"*. Geographical requirements for delivery of ancillary services is a challenge in developing these markets as well as the fact that grid components such as *"synchronous compensators and HVDC VSC-convertors have a potential to deliver system supporting services in competition with commercial power plants. This development demands transparency in the procurement process to secure optimal planning, operations and investments"*[36].

[32] *"Balancing responsibility and costs of wind power plants"* (2015) European Wind Energy Association, http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA-position-paper-balancing-responsibility-and-costs.pdf

[33] *"Mapping Demand Response in Europe today"* (2015) Smart Energy Demand Coalition, http://www.smartenergydemand.eu/wp-content/uploads/2015/09/Mapping-Demand-Response-in-Europe-Today-2015.pdf

[34] *"Technical and regulatory aspects of the provision of ancillary services by battery storage"* (2015) Younicos

35 *"Battery Energy Storage in the EU: barriers, opportunities, services and benefits"* (2016) EUROBAT, http://www.eurobat.org/sites/default/files/eurobat_batteryenergystorage_web.pdf p.30.

[36] "Markets for ancillary and system supporting services in Denmark" (2016) Energinet.dk

Two joint papers by Statkraft and Dong Energy point out that *"in the past, system services have played a marginal role in total economics of power plants. In the future, however, system services will be more important for the individual plant and the value (balance of supply and demand of these services) to the system are likely to be markedly higher"*, and that *"requirements put into tenders are crucial for the outcome"*.[37]

[37] *"Does the wholesale electricity market design need more products, or more control?"* Part 1 (2015) & Part 2 (2016) Dong Energy & Statkraft

2. Detailed measures assessed under Problem Area I, option 1(b) Strengthening short-term markets

2.1. Reserves sizing and procurement

2.1.1. *Summary table*

Objective: define areas wider than national borders for sizing and procurement of balancing reserves				
	Option 0: business as usual	Option 1: national sizing and procurement of balancing reserves on daily basis	Option 2: regional sizing and procurement of balancing reserves	Option 3: European sizing and procurement of balancing reserves
Description	The baseline scenario consists of a smooth implementation of the Balancing Guideline. Existing on-going experiences will remain and be free to develop further, if so decided. However, sizing and procurement of balancing reserves will mainly remain national as foreseen in the Balancing Guideline. Active participation in the Balancing Stakeholder Group could ensure stronger enforcement of the Balancing Guideline.	This option consists in developing a binding regulation that would require TSOs to size their balancing reserves on daily probablistic methodologies. Daily calculation allows procuring lower balancing reserves and, together with daily procurement, enables participation of renewable energy sources and demand response. This option foressees separate procurement of all type of reserves between upward (i.e. increasing power output) and downward (i.e. reducing power output; offering demand reduction) products.	This option involves the setup of a binding regulation requiring TSOs to use regional platforms for the procurement of balancing reserves. Therefore this option foresees the implementation of an optimisation process for the allocation of transmission capacity between energy and balancing markets, which then implies procuring reserves only a day ahead of real time. This option would result in a higher level of coordination between European TSOs, but still relies on the concept of local responsibilities of individual balancing zones and remains compatible with current operational security principles.	This option would have a major impact on the current design of system operation procedures and responsibilities and current operational security principles. A supranational independent system operator ('EU ISO') would be responsible for sizing and procuring balancing reserves, cooperating with national TSOs. This would enable TSOs to reduce the security margin on transmission lines, thus offering more cross-zonal transmission capacity to the market and allowing for additional cross-zonal exchanges and sharing of balancing capacity.
Pros		Pro – optimal national sizing and procurement of balancing reserves	Pro –regional areas for sizing and procurement of balancing reserves	Pro – single European balancing zone
Cons		Con – no cross-border optimisation of balancing reserves	Con – balancing zones still based on national borders but cross-border optimisation possible	Con – extensive standardisation through replacement of national systems, difficult and costly implementation
Most suitable option(s) Option 2. Sizing and procurement of balancing reserves across borders require firm transmission cross-zonal capacity. Such reservation might be limited by the physical topology of the European grid. Therefore, in order to reap the full potential of sharing and exchanging balancing capacity across borders, the regional approach in Option 2 is the preferred option.				

2.1.2. *Description of the baseline*

Balancing refers to the situation after markets have closed (gate closure) in which a TSO acts to ensure that demand is equal to supply. A number of stakeholders are responsible for organising the electricity balancing market:

- Transmission system operators ('TSOs') keep the overall supply and demand in balance in physical terms at any given point in time. This balance guarantees the secure operation of the electricity grid at a constant frequency of 50 Hertz.
- Balance responsible parties ('BRPs') such as producers and suppliers; keep their individual supply and demand in balance in commercial terms. Achieving this requires the development of well-functioning and liquid markets. BRPs need to be able to trade via forward markets and at the day-ahead stage. They also need to be able to fine-tune their position within the same trading day (e.g. when wind forecasts or market positions change).
- Balancing service providers ('BSPs') such as generators, storage or demand facilities, balance-out unforeseen fluctuations on the electricity grid by rapidly increasing or reducing their power output. BSPs receive a capacity payment for being available when markets have closed ('balancing capacity' also referred to as 'balancing reserve') and an energy payment when activated by the TSO in the balancing market ('balancing energy'). Payments for balancing capacity are often socialized via the transmission network tariffs, whereas payments for balancing energy usually shape the price that BRPs who are out of balance have to pay ('imbalance price').

Currently, national balancing markets in Europe have significantly different market designs and are operated according to different principles[38]. To achieve efficiency gains through a genuine European balancing market, it is essential to provide a set of common principles. As one can expect the adoption of the Balancing Guideline in 2017, it is possible to agree on the baseline, which can be built upon in the market design initiative.

The Balancing Guideline covers, in particular:

- Standardisation of balancing products[39] used by TSOs to maintain their system in balance. The starting point is a situation where, in Europe, the number of balancing products is estimated at some hundred. TSOs will have to reduce this number as much as possible to create a harmonised competitive market.
- Merit order activation of balancing energy based on European platforms, i.e. operational within 4 years after the entry into force, where all TSOs will have access while taking into account cross-zonal transmission capacity available or released after intraday gate closure.

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[38] ENTSO-E survey on ancillary services, May 2016: https://www.entsoe.eu/Documents/Publications/Market%20Committee%20publications/WGAS%20Survey_04.05.2016_final_publication_v2.pdf?Web=1

[39] The term "product" refers to different balancing services which can be traded, such as the provision of balancing energy with different speeds of delivery.

- Single marginal pricing ('pay-as-cleared') which reflects scarcity for the remuneration of the participants in the balancing market (i.e. the payment that a participant receives for providing balancing energy to be the same payment as the imbalance price). Thus being individually in imbalance but contrary to the imbalance of the system as a whole, thus helping the system as a whole to stay balanced, gets rewarded rather than penalized.
- Harmonisation of the length of the imbalance settlement periods ('ISP' i.e. the time over which it is measured whether BRPs stay in balance, i.e. they did not sell more electricity than they produced). Trading products are generally not shorter than, but can be multiples of ISP. The length of the ISP is thus of relevance for all market timeframes and not just for the balancing market. In cross-border trade, the biggest common ISP has to be used. Thus, the smallest trading product across Europe is currently 60 minutes which corresponds to the length of the longest ISP across Member States. However, where two Member States have shorter ISPs, shorter products can be traded across their border (e.g. 30 minutes between France and Germany). To increase the trade of short products, the Balancing Guideline proposes a shift to harmonized 15 minutes ISPs[40].

The Balancing Guideline also provides the baseline for integrating renewable energy sources and demand response in the balancing market, in particular:

- Balancing energy gate closure time (i.e. the point in time after which there can be no more balancing energy offers from BSPs) as close as possible to physical delivery, and at least after intraday cross-zonal gate closure (thus a maximum of 60 minutes before real time). Shorter gate closure time allows wind or PV generators and demand response aggregators to update their forecast and to offer remaining energy to the electricity balancing market.
- Possibility to offer balancing energy without a balancing capacity contract. The procurement timeframes for balancing capacity have generally long lead times for which wind or PV power producers and demand response aggregators cannot secure firm capacity.
- Shorter procurement timeframes for balancing capacity (close to real time).

It would be, however, out of the scope of the Balancing Guideline to aim for full harmonization of the currently very diverse balancing markets. The Balancing Guideline includes many exemptions (e.g. central dispatch systems, procurement rules for balancing capacity) and possible derogations (e.g. dual pricing as opposed to single marginal pricing). It is therefore essential that all national balancing markets adhere to a minimal set of common principles.

In addition, balancing reserves are currently mainly sized and procured by TSOs on a national level (except for the Nordic countries and the Iberian Peninsula). This contrasts with the increasing demand for balancing reserves across Europe over the coming

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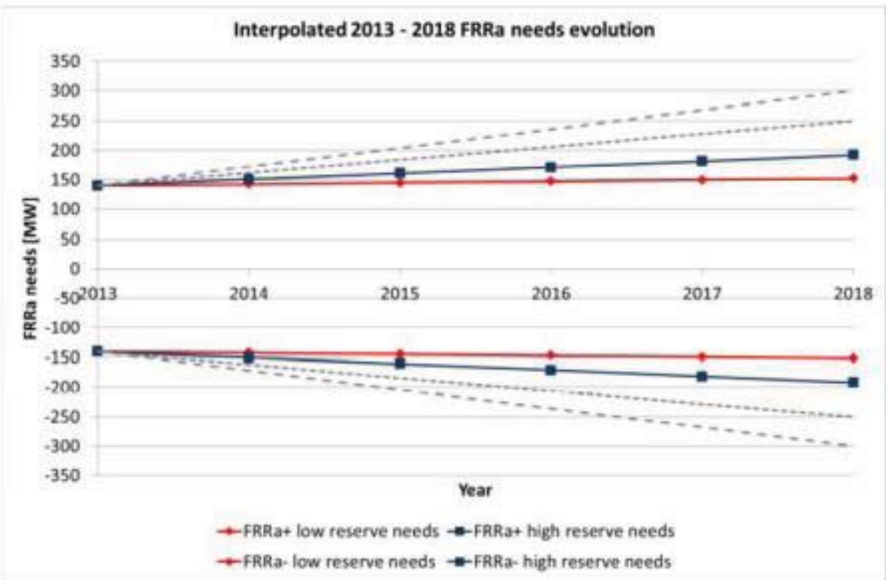
[40] "*Frontier Economics report on the harmonisation of the imbalance settlement period*", April 2016 https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/CBA_ISP/ISP_CBA_Final_report_29-04-2016_v4.1.pdf

decades which is mainly due to large-scale cross-border flows and high volumes of variable RES E generation. Most of the TSOs are sizing their balancing reserves based on potential outages of HVDC interconnectors and forecast errors of renewable energy sources. Despite trends observed in the market (see below figure from ELIA, the Belgian TSO)[41] on the evolution of balancing reserves needs from 2013 to 2018, no significant binding harmonisation is achieved on this subject in the Balancing Guideline.

Graph 1: Interpolated ranges for the volume of reserves needed between 2013 and 2018



Source: Belgian TSO report on the evolution of ancillary services needs to balance the Belgian control areas towards 2018, pp. 32)

In their Market Monitoring report 2014[42], ACER points out that in most European markets, the procurement of balancing capacity represents the largest proportion of the overall costs of balancing. The excessive weight of the balancing capacity procurement costs may suggest that the procurement of balancing capacity is not always optimised. ACER emphasis the importance of optimising the procurement costs of balancing capacity, including separate procurement of upward and downward balancing capacity and shorter procurement timeframes.

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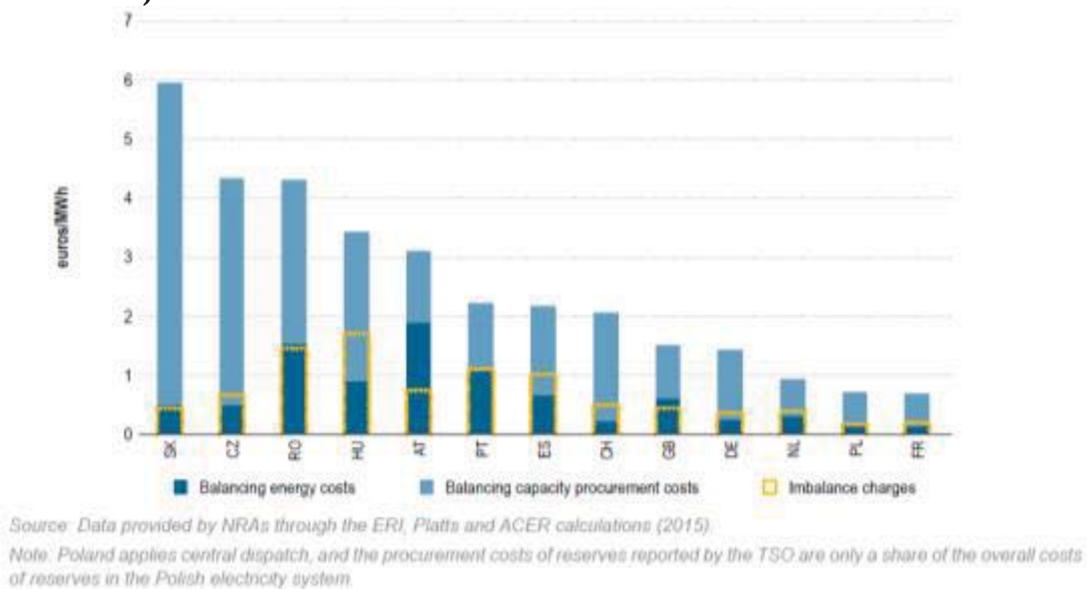
[41] Belgian TSO report on the evolution of ancillary services need to balance the Belgian control area towards 2018, May 2013 http://www.elia.be/~/media/files/Elia/Grid-data/Balancing/Reserves-Study-2018.pdf

[42] *"Market Monitoring Report 2014"* (2015) ACER, pp. 210.

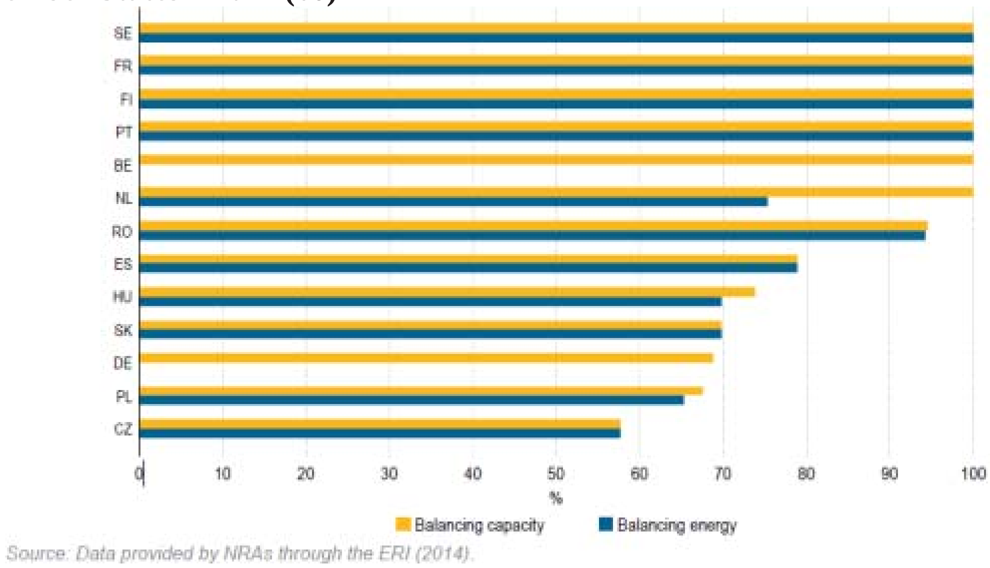
Graph 2: Overall costs of balancing (capacity and energy) and imbalance charges over national electricity demand in a selection of European markets – 2014 (euros/MWh)



Source: "*Market Monitoring Report 2014*" (2015) ACER, *pp. 209*

Moreover, because only flexible generation assets can provide balancing reserves, balancing markets tend not to be very competitive. Balancing markets are regularly rather concentrated on the supply side as only assets able to adjust production or consumption fast can participate. In their Market Monitoring report 2014, ACER also illustrates the very high level of concentration in the procurement of balancing capacity.

Graph 3: Level of concentration in the provision of balancing services from automatic Frequency Restoration Reserves (capacity and energy) for a selection of Member States – 2014 (%)



Source: "Market Monitoring Report 2014" (2015) ACER, pp. 207

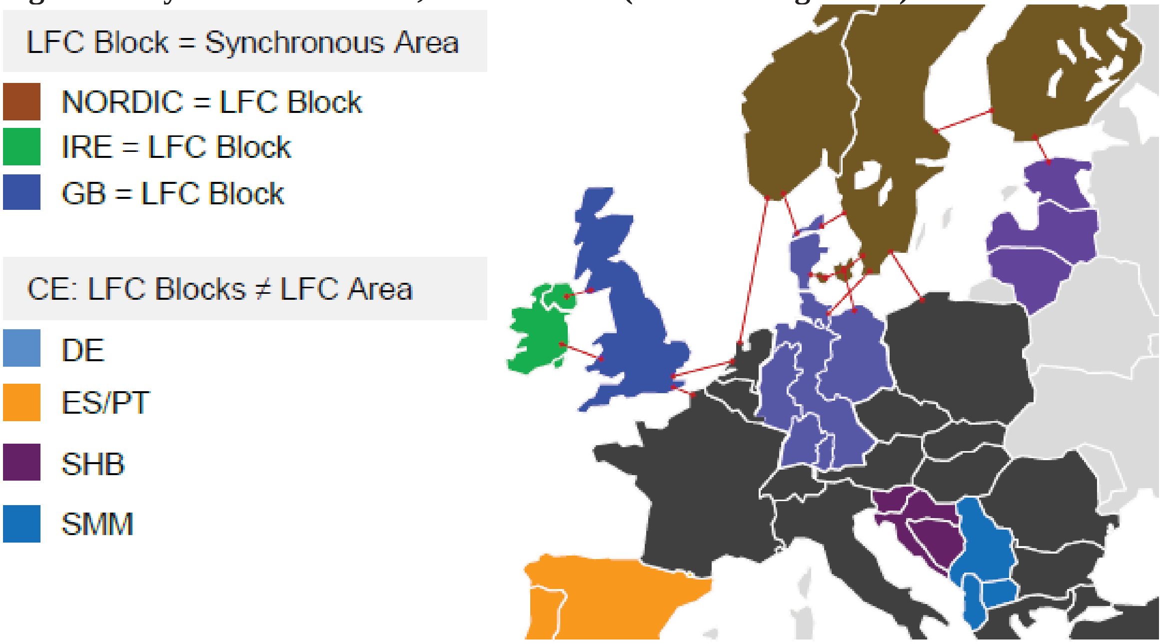
Integrating balancing markets will increase competition and hence will save overall costs. These costs are largely determined by the size of the network area for which the balancing reserves are being procured (also referred to as 'balancing zone' or 'load-frequency control block') and the frequency with which this is done. The size of the reserves that need to be set aside depends on the size of unforeseen events within a given balancing zone. Larger zones across TSO-control areas (effectively across Member States) will result in lower total balancing reserve requirements and reduce significantly the need for back-up generation, as the risks to be covered are smaller than with a simple addition of the risks of two small zones. To this end, a limited number of wider balancing zones should be defined by the needs of the network rather than national borders.

2.1.3. *Deficiencies of the current legislation (see also Section 7.4.2 of the evaluation)*

Recitals and provisions containing reference to transparent, non-discriminatory and market-based procedures for the procurement of balancing capacity are contained in the Electricity Directive. However, there is nothing more specific to the procurement rules. As part of the regional cooperation of TSOs, Article 12.2 of the Electricity Regulation refers to the integration of balancing and reserve power mechanism. However, no further details are being developed concerning the sizing of balancing reserves at regional level.

The Guidelines on System Operation (approved in Comitology on 4th of May 2016) harmonise terms, methodologies and procedures for sizing balancing reserves, but it is expected that balancing zones (or LFC Blocks) will remain unchanged and mainly based on national borders (except for Nordic countries and Spain-Portugal) as illustrated below.

Figure 1: Synchronous Areas, LFC Blocks (or balancing zones) and LFC Areas



Source: ENTSO-E supporting document for the Network Code on Load-Frequency Control and Reserves, 2013, pp. 42

The Balancing Guideline (not yet approved in Comitology) intends to set out rules for the procurement of balancing capacity, the activation of balancing energy and the financial settlement of BRPs. It would also require the development of a harmonised methodology for the reservation of cross-zonal transmission capacity for balancing purposes. However sharing and exchange of balancing capacity would not be mandatory under the Balancing Guideline but encouraged.

2.1.4. *Presentation of the options*

Option 0 - BAU

The baseline scenario consists of a smooth implementation of the Balancing Guideline where sharing and exchange of balancing capacity are not mandatory. In this way, the existing on-going experiences (such as the regional sizing and procurement of balancing reserves in the Nordic countries and the Iberian Peninsula) will remain and be free to develop further and integrate, if so decided by the participating parties. Isolated and likely incompatible projects may be implemented across Europe.

Procurement arrangements such as shorter contracting period close to real time should be enforced in line with the development of a methodology for the reservation of cross-zonal transmission capacity for balancing purposes.

Option 0+: Non-regulatory approach

The Third Package does not address the provision of regional sizing and procurement of balancing reserves in a way that could be used to stronger enforce existing legislation.

Specific parts dealing with transparency, non-discrimination and market based rules can be found in the Article 15 of the Electricity Directive. Others parts dealing with the regional cooperation of TSOs on balancing and the optimal allocation of capacity across timeframes can be found in Article 12.2 and Annex 1.2.6 of the Electricity Regulation.

Voluntary cooperations between TSOs for sharing and exchaning balancing capacity could be further supported thanks to an active participation in the Balancing Stakeholder Group established by ACER and ENTSO-E for an early implementation of the Balancing Guideline. However no mandatory provisions in the Balancing Guideline request TSOs to size and procure reserves at regional level.

Option 1 – National sizing and procurement of balancing reserves on a daily basis

This option consists in developing a binding regulation that would require TSOs to size their balancing reserves on daily probabilistic methodologies (i.e. based on different variables such as RES E generation forecasts, load fluctuations and outage statistics). This method is opposed to a deterministic approach which consists of sizing the balancing reserves on the value of the single largest expected generation incident. Daily calculation allows procuring lower balancing reserves and, together with daily procurement, enables participation of renewable energy sources and demand response.

Shorter procurement timeframes for balancing capacity facilitate the participation of wind generators and demand response aggregators which cannot secure firm capacity over long lead times, or storage operators, which do not have to guarantee specific amounts of energy stored over long periods. This option foresees separate procurement of all types of reserves between upward (i.e. increasing power output; offering demand reduction) and downward (i.e. reducing power output; offering demand increase) products.

Option 2 – Regional sizing and procurement of balancing reserves

This option involves the set up of a European binding regulation requiring TSOs to use regional platforms for the procurement of balancing reserves. Mandatory sharing and exchange of balancing capacity requires firm cross-zonal transmission capacity. Therefore this option foresees the development of an optimisation process for the allocation of transmission capacity between energy and balancing markets, which then implies procuring reserves only a day ahead of real time.

This option thus has the focus on a more integrated approach on the sizing and procurement of balancing reserves themselves. Mandatory regional procurement of balancing reserves would require changing and harmonizing adjacent business and related operational processes. Mandatory regional sizing of balancing reserves might have an impact on system operation procedures and responsibilities, at least procedurally shifting security of supply-related tasks (such as system's state analysis) to a supranational level (possibly to newly-established regional operational centres ('ROCs'), see also Section 2.3).

TSOs would still be responsible for real-time activation of the balancing capacity procured; however they would only have access to the regional platforms for the procurement of balancing capacity which would assume harmonized procurement timeframes and centralised optimisation algorithm requiring firm cross-border transmission capacity to be available. Balancing reserves would be estimated on a daily basis and based on probabilistic methodologies.

Option 3 – European sizing and procurement of balancing reserves

This option would result in a significant evolution of the current design in which European electricity systems are operated. This would have a major impact on the current design of system operation procedures and responsibilities.

This option involves setting up a binding European framework to ensure that all Member States implement a single market design for sizing and procurement of balancing reserves. A supranational independent system operator ('EU ISO') would be responsible for sizing and procurement of balancing reserves, cooperating with national TSOs. This would enable TSOs to reduce the security margin on transmission lines, thus offering more transmission capacity to the market and allowing for additional sharing and exchanges of balancing capacity.

2.1.5. *Comparison of the options*

Economic impacts

All three options can capture some of the potential social welfare opportunities. Option 3 would be the most effective in achieving an optimal sizing and procurement of balancing reserves at European level. However, it might not be feasible as sharing and exchanges of balancing capacity require firm cross-zonal transmission capacity. Such reservation might be limited by the physical topology of the European grid (e.g. geographical distribution of the balancing reserves to maintain operational security[43]). Option 1, which

[43] ENTSO-E supporting document for the Network Code on Load-Frequency Control and Reserves, 2013, pp. 75

foresees daily sizing of balancing reserves at national level and separate procurement of downward and upward balancing capacity, would result in an increased participation of wind power producers and demand response aggregators in the balancing market. While the improvements of national rules regarding sizing and procurement of balancing reserves would allow savings around EUR 1.8 billion, it would not reap the full potential of cross-border exchanges. Daily sizing and procurement of balancing reserves could therefore be optimally performed at regional level. The preferred option is thus Option 2, which brings savings of around EUR 3.4 billion.

Table 1: Economic impacts by option

	BAU	Option 1	Option 2	Option 3
Balancing reserves needs (GW)	53.4	52.1	29.9	17.1
Balancing reserves needs reduction	-	3%	44%	68%
Annual savings (EUR billion)	**-**	**1.8**	**3.4**	**4.5**

Source: METIS

Regulatory impact

The costs of sizing and procuring balancing reserves at regional level are mainly linked to the possibility to add a task to the newly-established regional operational centres ('ROCs') (see also Section 2.3 of the present annexes to the impact assessment). System state analysis would have to be performed on a daily basis and regional level by the ROCs, together with the setting-up of regional plaforms for the procurement of balancing reserves. The option entailing the smallest change (Option 1) involves costs significantly less than the other two options. Option 2 is likely to be more expensive as a result of the additional tasks to ROCs and the setting-up of several new platforms for the exchange or sharing of balancing reserves.

2.1.6. *Subsidiarity*

The subsidiarity principle is fulfilled given that the EU is best placed to provide for a harmonised EU framework for common sizing and procurement of balancing reserves. Most Member States currently take national approaches to size and procure balancing reserves including often not allowing for foreign participation. As common sizing and procurement of balancing reserves requires neighbouring TSOs' and NRAs' full cooperation, individual Member States might not be able to deliver a workable system or only provide suboptimal solutions.

Providing mandatory regional sizing and procurement of balancing reserves would be also in line with the proportionality principle given that it aims at preserving the properties of market coupling and ensuring that the distortions of uncoordinated national balancing mechanisms are corrected and the internal market is able to deliver the benefits to consumers.

2.1.7. *Stakeholders' opinions*

Most respondents from the Market Design consultation agreed with the need to speed up the development of integrated short-term (balancing and intraday) markets. A significant number of stakeholders argue that there is a need for legal measures, in addition to the technical network codes and guidelines under development, to speed up the development of cross-border balancing markets, and provide for clear legal principles on non-discriminatory participation in these markets.

In ENTSO-E's view a parallel harmonization of balancing energy and balancing capacity procedures would lead to unreasonably high effort for TSOs and would introduce additional uncertainty and insecurity for the operation of the electricity system if made mandatory. However ENTSO-E and ACER recognise that common cross-border procurement of reserves is a good target in the long-term.

The March 2016 Electricity Regulatory Forum (the "Florence Forum"), a forum for stakeholders to engage on wholesale market regulatory issues, made the following relevant conclusion:

"The Forum stresses the importance of balancing markets for a well-integrated and functioning EU internal energy market. It encourages the Commission to swiftly bring the draft Balancing Guideline to Member States for discussion, ideally before the summer, with a view to reaching agreeement in autumn this year. It considers, however, that there may still be improvements needed and ask the Commission to consider the provisions of the draft Guideline carefully before presenting a formal proposal.

The Forum supports the view that further steps are needed beyond agreement and implementation of the Balancing Guideline. In particuler, further efforts should be made on coordinated sizing and cross-border sharing of reserve capacity. It invites the Commission to develop proposals as part of the energy market design initiative, if the impact assessment demonstrates a positive cost-benefit, which also ensure the effectiveness of intraday markets."

2.2. Removing distortions for liquid short-term markets

2.2.1. *Summary table*

Objective: to remove any barriers that exist to liquid short-term markets, specifically in the intraday timeframe, and to ensure distortions are minimised.			
	Option 0	Option 1	Option 2
Description	Business as usual Local markets mostly unregulated, allowing for national differences, but affected by the arrangements for cross-border intraday and day-ahead market coupling. Stronger enforcement and volunatry cooperation There is limited legilsation to enforce and voluntary cooperation would not provide certainty to the market.	Fully harmonise all arrangements in local markets.	Selected harmonisation, specifically on issues relating to gate closure times and products.
Pros	Simplest approach, and allows the cross-border arrangements to affect local market arrangements. Likely to see a degree of harmonisation over time.	Would minimise distortions, with very limited opportunity for deviation.	Targets issues that are particularly important for maximising liquidity of short-term markets and allows for participation of demand response and small scale RES.
Cons	Differences in national markets will remain that can act as a barrier.	Extremely complex; even the cross-border arrangements have not yet been decided and need significant work from experts. Additional benefit unclear.	May still be difficult to implement in some Member States with implication on how the system is managed – central dispatch systems could, in particular, be impacted by shorter gate closure time.
Most suitable option(s): Option 2 – Provides a proportionate response targeting those issues of most relevance.			

2.2.2. *Description of the baseline*

Intraday markets usually open several hours before the day of delivery and allow market participants to trade energy products i.e. discrete quantities of energy for a set amount of time - close to real time and as short as five minutes before delivery.

Liquid intraday markets will form a critical part of a European energy market that is able to cost-effectively accommodate an increasing share of variable renewable sources, allow for more demand-side participation, and allow for energy prices to reflect scarcity.

> *"Liquidity is a measure of the ability to buy or sell a product – such as electricity - without causing a major change in its price and without incurring significant transaction costs. An important feature of a liquid market is the presence of a large number of buyers and sellers willing to transact at all times"*[44].

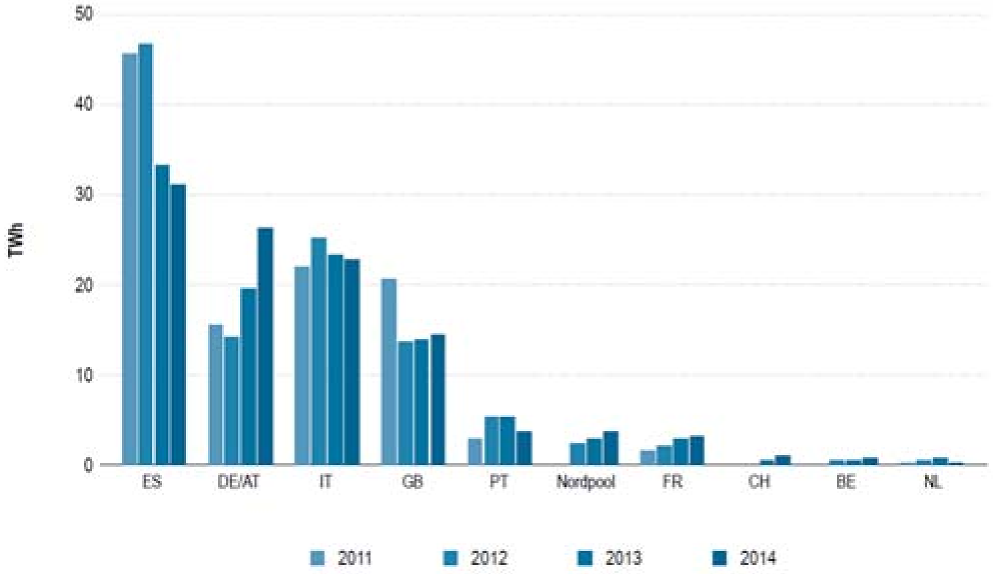
Maximising liquidity in the intraday market will increase competitive pressure, increase confidence in the resulting energy prices, and allow adjustment of positions close to real time, thus reducing the need for TSO actions in the balancing timeframes (although it should be noted that this will not by itself reduce the need for remedial actions by TSOs to address congestion in internal grids).

- The more variable source of renewable generation in the EU energy mix, the more impact of errors in forecasting of weather and demand. Allowing close-to-real-time trading will allow suppliers and producers to take account of the most up-to-date information and, therefore, reduce risk of being out of balance.
- The more trading in this market, the more likely it is to reflect the overall value of staying in balance, thereby increasing confidence in the price. This in turn will affect price formation in the day-ahead market and in forward markets.

Most Member States have organised intraday markets. In their Market Monitoring Report, ACER points out a general trend to an increase in the volumes traded in national intraday markets.

[44] Ofgem, https://www.ofgem.gov.uk/electricity/wholesale-market/liquidity

Figure 1 – ID traded volumes in selection of EU markets – 2011-2014 (TWh).



Source: PXs and the CEER national indicators database (2015), as reported in "Market Monitoring Report 2014" (2015) ACER.

However, there remains significant scope for increasing liquidity. In the same report, ACER analyse 13 markets that make up 95% of the liquidity in intraday markets, using as a liquidity indicator the ratio of energy volumes traded to demand. The following shows that only 5 markets had a ratio above 1%.

ES	IT	PT	DE	GB	SI	BE	SE	LT	FR	CZ	NL	PL
12.1%	7.4%	7.6%	4.6%	4.4%	1.0%	1.0%	1.0%	1.0%	0.7%	0.7%	0.2%	0.1%

The organisation of national intraday markets is largely unregulated in EU law. A degree of harmonisation has developed naturally, partially due to common actors in national markets. However, significant differences still remain. In particular:

- whilst most countries operate a continuous trading approach, some have intra-day auctions;
- gate closure times (i.e. when the market closes) vary from between 5 minutes (BE and NL) to 120 minutes (HU) ahead of real time. In the Iberian market, which operates auctions, the shortest gate closure time is just over two hours, and can extend even further depending on the hour of delivery;
- the granularity of products varies between 60 minute products and 15 minute products;
- the minimum size of bids varies between 0.1MWh to 1MWh;
- the types of orders vary considerably;
- demand response is not consistently allowed to participate;
- whether bidding is at unit-level or portfolio-level;
- whether the organised intraday-markets are exclusive (i.e. preventing bi-lateral trading).

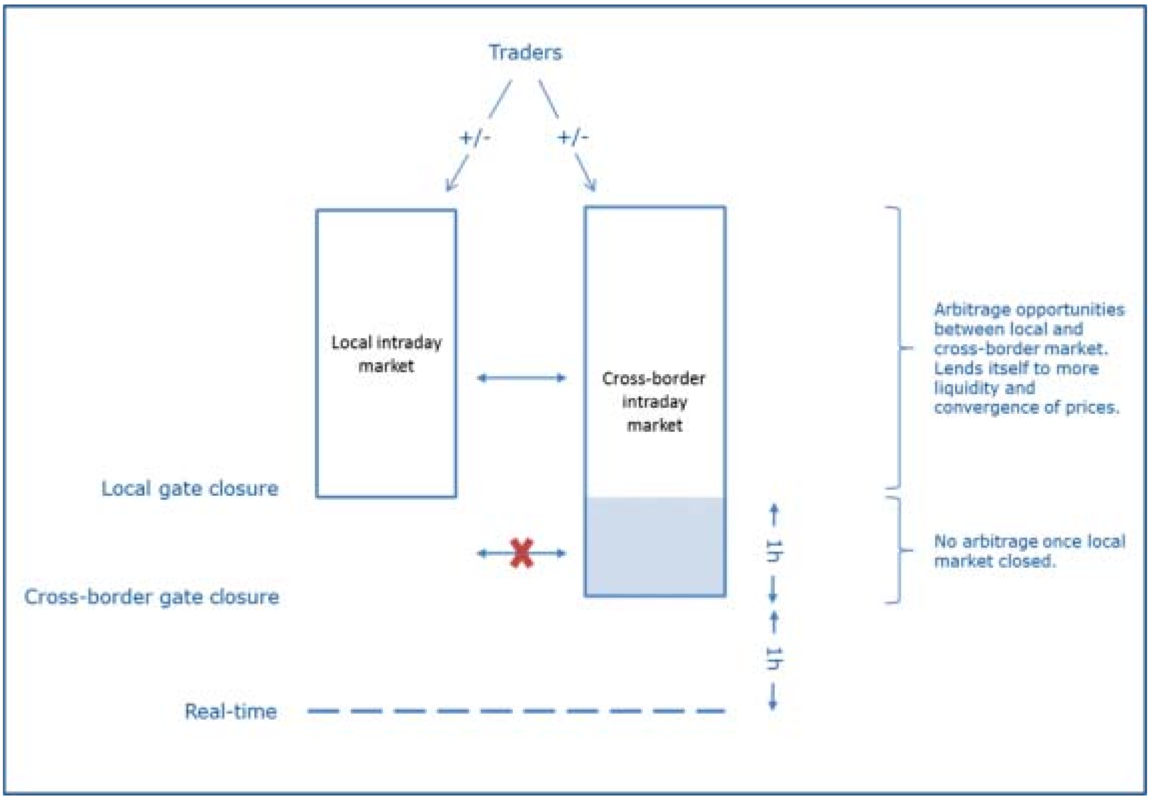
Currently, cross-border trading in the intraday timeframe is not harmonised, is generally on a border-by-border basis and the total traded volumes are low: in 2014 only 4.1% of IC capacity was used intraday, compared to 40% day-ahead.

The CACM guideline[45] envisages a new, EU-wide cross-border market in the intraday timeframe. Local markets will be indirectly impacted by its introduction, essentially because it provides an extra choice for market participants on which platform to trade. There are important interactions, notably because the two markets co-existing in this way has the potential to split liquidity (i.e. split the trading across two markets as opposed to one, thereby reducing the benefits of a highly liquid market). The more differences that exist between local markets and between local markets and the cross-border market, the greater the impact is likely to be as arbitrage opportunities between them will be reduced.

One issue exists in particular – that of gate closure times. The below diagram is an illustration of the potential interactions between local and cross-border markets. While both are open for trading, market participants can chose the best one, most likely driven by price and/or products which match their needs, but potentially also by functionality and ease-of-use of the trading platform. As such there should be a general trend towards convergence of prices in these two markets as they will effectively be in direct competition with each other. The more similarities in the specificities of the markets the more likely this is to be the case. However, if the local market closes before the cross-border market, the arbitrage opportunities are reduced as the market participants cannot freely trade between the two. There is also a risk that local rules will mean that continued cross-border trading will not be possible once the local market has shut, for example because it is on this basis which the suppliers and producers provide 'firm' details on their contracted energy to the TSO. The existence of different products and arrangements, and even different IT systems on which to trade, also bears the risk of splitting liquidity between different markets. However, whilst the longer-term objective should be to have one, common market where all trading takes place and where liquidity is 'pooled', given the starting point it is not necessarily beneficial to deliver this by harmonising all arrangements in the short-term, as it could involve moving to the 'lowest common denominator,' as described further below.

45 Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management.

Figure 2 – Example co-existence of local and cross-border markets, where local market closes before cross-border.



The design of some national markets may limit the ability for RES E or Demand Response to participate, as they will prefer shorter products as this will help them accommodate more variability in generation and demand. Also, if products do not at least reflect the imbalance settlement period, then market participants will not have the ability to balance themselves sufficiently frequently.

Finally, the closer to real time that market parties are allowed to trade, the more likely it is that their supply and demand will be in balance when it comes to delivering and consuming energy. This is especially relevant in a market sensitive to weather fluctuations where changes can happen after the market has closed and the participants are not able to buy or sell energy to make up for this. It therefore becomes the responsibility of the TSO as part of the balancing market. However, the risk is that, if set too close, TSOs will not have the time they need after being informed of the final market results to manage the system and, in particular, deal with internal bottlenecks.

2.2.3. *Deficiencies of the current legislation*

As detailed above, there is very limited legislation in this area. The most significant piece is the CACM Guideline, but this only indirectly addresses the operation of national markets and, in most cases, will not directly lead to standardised trading within local markets, which thereby potentially creates a barrier to cross-border trade and liquidity.

The Evaluation Report for market design concluded that *"the Third Energy Package does not ensure sufficient incentives for private investments in the new generation capacities and network because of the minor attention in it to effective short-term markets and prices which would reflect actual scarcity."*[46]

2.2.4. <u>*Presentation of the options*</u>

Option 0 – Business as Usual

This option would leave local markets mostly unregulated, allowing for national differences, but influenced by the arrangements for cross-border intraday and day-ahead market coupling. The CACM Guideline requires the definition of a gate closure time on each bidding zone border, which can be a maximum of 60 minutes. This could impact decisions taken at national level, but this is not certain and differences are likely to remain. Further, the definition of the products that can be taken into account in the cross-border system are to be determined under the CACM Guideline which could, again, impact the products which are provided in local markets.

Option 0+ Non-regulatory approach

There is very limited legislation in this area. Stronger enforcement of current rules therefore does not provide scope to achieve a larger degree of harmoninsation of intraday trading arrangements.

Voluntary cooperation has resulted in significant developments in the market and a lot of benefits. However it may not provide for appropriate levels of harmonisation or certainty to the market and legisaltion is needed in this area to address the issues in a consistent way.

Option 1 – Fully harmonise all arrangements in local markets.

This option would see all arrangements harmonised, including gate opening times, gate closing times, products to be offered, whether markets are exclusive, and mandatory continuous trading rather than auctions. Gate closure time would be established as close to real time as possible, to provide maximum opportunity for the market to balance its positions before it became the TSO responsibility. Markets would be exclusive – i.e. no bilateral trading – and power exchanges would be obliged to offer small products, in size and duration – likely a minimum of 0.1MWh in 15 minute blocks. Demand response would be able to participate in all markets.

Given the difference in technical characteristics of different markets (i.e. some have very limited internal congestion so very short gate closure times are technically feasible, whilst others need more time to take remedial actions), this option would likely see some markets becoming larger (with gate closure times closer to real time) and some smaller (with gate closure times having to move further away from real time, depending on the

[46] Section 7.3.2 of the Evaluation

precise time chosen). It would also mean that products would not necessarily reflect the difference in national systems.

Given the technicalities of this option, it would likely be developed through implementing legislation.

Option 2 - Selected harmonisation, with additional flexibility

This option would introduce standardisation of gate closure time and products in a more flexible way, specifically allowing some flexibility in national markets to reflect their differentiated nature. In particular, under this option, legislation would specify:

- that intraday gate closure time in national markets must not be longer than the cross-border intraday gate closure time. This would ensure that national markets are not 'taken out of the picture' before the cross-border markets close, and would, in effect, mean that at a minimum market participants are allowed to trade as close as one hour ahead of real time.
- that power exchanges must offer products that reflect the imbalance settlement period. This will ensure that market participants are able to trade at a frequency which allows them to stay in balance.
- that barriers to demand response participating in intraday markets must be minimised – specifically, minimum bid size should allow for participation and there should be no administrative barriers put in place.

This option would also see more principles added to legislation, with the aim of progressive harmonisation over time on those design features not touched.

2.2.5. *Comparison of the options*

Option 0 (Business as usual) would keep the *status quo* and leave intraday markets to evolve within Member States, with no guarantees they would develop along the same lines, except in some areas that existing legislation touches (for example, on minimum and maximum bid prices). There would likely be an impact as a result of the implementation of market coupling in the intraday time-frame. With significant differences, there is a risk that liquidity is split and benefits of short-term markets to the integration of RES E and demand response muted.

Option 1 – full harmonisation – would likely see significant changes in a number of markets. It would involve selecting a gate closure time and applying that to all national markets. Whilst the precise timing could vary, it would mean that some countries would need to keep their markets open longer, and some would need to close their markets earlier than they currently do (notably in Belgium and the Netherlands, where trades can currently take place up to 5 minutes prior to delivery) – harmonising gate closure times to that of the shortest in Europe would likely be unachievable for many Member States, particularly larger ones where the TSO requires more time between knowing the market results and real time in order to solve internal congestion (the market is blind to congestion within a bidding zone).

This option would also involve harmonising other aspects, as detailed above. Power exchanges can be seen as the conduit for energy trades across borders so harmonising the rules on which trading takes place will minimise differences between national markets and with the common cross-border market. By increasing the arbitrage opportunities across these markets, the risk of splitting liquidity is reduced.

On the surface, this might seem like an appropriate response akin to other single market measures that harmonise standards so that they can be traded within the EU with minimal barriers. However, in reality this is likely to be much more complex. A significant amount of the process is IT-driven, and the arrangements have not yet been put in place – it would therefore be very difficult to determine what the local arrangements should be. Further, there is a lack of evidence that such harmonisation would indeed lead to more cross-border trade – the costs associated with changing IT could be significant with little benefit.

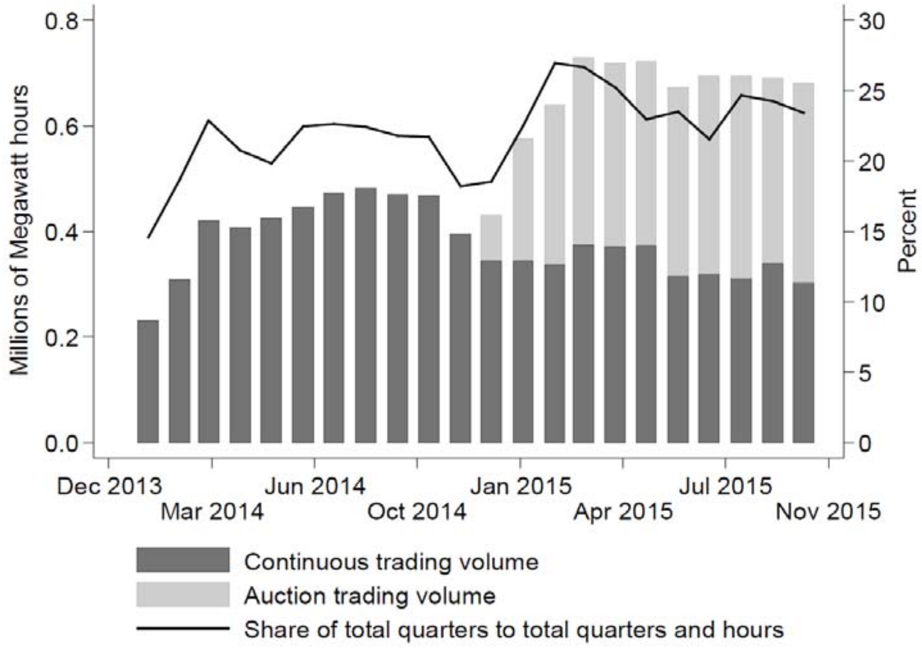
Given that the common cross-border market will likely be more complex (e.g. given the number of variables, Member States, the fact that calculations will need to consider available cross-border capacity) in the immediate future this market, and the IT infrastructure that supports it, may not be able to accommodate the more granular market arrangements that exist in some Member States. As such, moving all national markets to the same design details of that of the cross-border market could entail some having to reduce their granularity, move gate closure time further away from real-time, etc. This would not fit with the objectives of the present proposal, which aims for increased flexibility.

Option 2, however, would provide a much more proportionate response. Rather than specifying a value for the gate closure time in local markets it would specify that it should be no longer than the cross-border gate closure time. It will provide more opportunity for arbitrage between markets. It will also move gate closure times closer to real-time in many markets, which will provide more opportunities for RES E to balance themselves and demand response to participate in the market, without forcing those markets which already apply very short-term trading rules to switch to longer timeframes. With regards to products the markets should be able to accommodate demand-response and small-scale RES E. It will also leave the most technical characteristics to the implementation of the CACM Guideline, which has the advantage of allowing specifics to be discussed in detail with market parties and for more flexibility, i.e. allowing for easy adaptation if and when requirements need to change.

Whilst this option will not eliminate the risk of splitting liquidity, there is in fact some evidence that two markets can co-exist and increase overall traded volumes. In a study looking at the impact of the introduction of an intraday auction for 15 minute products in Germany[47], it was found that, whilst the auction pulled some value away from the continuous intraday market, the total traded volumes increased.

[47] "*Intraday Markets for Power: Discretizing the Continuous Trading*" Karsten Neuhoff, Nolan Ritter, Aymen Salah-Abou-El-Enien and Philippe Vassilopoulos (2016)

Figure 3: Volumes on the 15mn intraday market and the share of quarters in total trading volumes (quarters+hours), EPEX (DE)



Source: Neuhoff et al (2016)

The option will also provide a good starting point for progressively harmonising with the longer-term aim of **one, common intraday market with local specificities minimised to situations where they are justified due to local differences.**

Specific impacts relating to changes in short-term markets are discussed in Section 6.1.3. With regards to intraday, the results of the modelling indicate positive impacts of harmonising intraday arrangements in Europe, specifically allowing for the further reduction of RES E curtailment and lesser use of replacement reserves by 460 GWh and 95 GWh, respectively

2.2.6. *Subsidiarity*

Given that the EU energy system is highly integrated, prices in one country can have a significant effect on prices in another, as can arrangements in local markets. Differences in the operation of local markets can present a barrier to the cross-border trade of energy, and continuing differences between local markets, and between local markets and the single cross-border market, risks splitting liquidty and constraining the benefits of a common cross-border market This will impact on liquidity and the amount of trading which can take place, as well as erode the benefits of competition and a larger market place in which energy can be bought and sold.

EU-level action is, therefore, necessary to ensure that the national markets are comparable, that they enable maximum cross-border trading to happen, and facilitate liquidity as much as possible. .

There is also a critical link with the CACM Guideline, which establishes principles and required further methodologies for the operation of intraday markets in the cross-border context, as well as a link with the upcoming Balancing Guideline. EU-level action is required to ensure that trading in local markets can reap maximum benefits of the cross-border solution under development.

2.2.7. _Stakeholders' opinions_

Most stakeholders agree on the importance of liquid short-term markets, particularly intraday and balancing, to the efficient operation of the internal electricity market. They are, in general, seen as a critical part of ensuring that RES E can be propely intergrated, notably allowing renewable generators to trade closer to real-term, as well as to stimulating investment in sources of flexibility such as demand response. Most call for speedy implementation of common cross-border intraday trading (market coupling) via the XBID project, whilst recognising the progress that has already been made in day-ahead market coupling.

Wind Europe calls upon the EU to "*ensure continuous intraday trading with harmonised gate closure times closer to real time; complementary auctions may be introduced to increase liquidity*". They argue that "*implementing well-functioning intraday markets across borders with gate-closure close to real-time will 1) provide renewable producers with opportunities to adjust their schedule in case of forecasts errors, 2) smooth out the variability induced by renewable in-feed over broader geographical areas*"[48].

In their publication *"Electricity Market Design: fit for the low-carbon transmision"*, Eurelectric state:

"The development of robust cross-border intraday and balancing markets will be crucial to ensure that the system remains balanced as the share of renewables continues to grow. It is therefore necessary to promote a liquid continuous implicit cross-border intraday market with harmonised products in all member states, while capacity pricing shall not drain liquidity nor reduce the speed of market processes. The market shall be enabled to determine the most economic dispatch until a gate closure set as close to real-time as possible (e.g. 15 minutes). TSOs shall only perform the residual balancing of the system."[49]

SolarPower Europe state *"progress is needed in particular with a view to achieving better liquidity and integration of intraday and balancing markets. These short-term markets are crucial as variable renewable energy sources take a more important role in the power mix. Products and services should be re-defined to improve the granularity of these markets and enable the sale of different system services that solar power and other renewables, but also storage and demand participation can provide."* [50]

ENTSO-E make the point that *"Accurate short-term market price formation is needed to reveal the value of flexibility in general and of DSR specifically"*[51] and ACER/CEER that "*it is imperative that everything is done to make sure that price signals reflect scarcity and to create shorter-term markets which will reward those who provide the flexibility services which the system increasingly needs."* Further, they state that *"the intraday and*

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48 *"A market design fit for renewables"*. Wind Europe submission of 27 June 2016

49 *"Electricity Market Design: fit for the low-carbon transmision"*. Eurelectirc 2016, available at http://www.eurelectric.org/media/272634/electricity_market_design_fit_for_low-carbon_transition-2016-2200-0004-01-e.pdf

50 *"Creating a competitive market beyond subsidies"* July 2015,

51 *Market Design of Demand Side Response"* Policy Paper, November 2015

balancing markets will be increasingly important to valuing flexibility and there needs to be a push to deliver the cross-border intraday (XBID) project and to implement the Network Code on Electricity Balancing as soon as possible."[52]

The March 2016 Electricity Regulatory Forum (the "Florence Forum"), a forum for stakeholders to engage on wholesale market regulatory issues, made the following relevant conclusion:

"The Forum acknowledges that, whilst cross-border day-ahead and intraday markets will see significant harmonisation as part of the implementation of the Capacity Allocation and Congestion Management guideline, there is significant scope for ensuring that national markets are appropriately designed to accommodate increasing proportions of variable generation. In particular, the Forum invites the Commission to identify those aspects of national intraday markets that would benefit from consistency across the EU, for example on within-zone gate closure time and products that should be offered to the market. It also requests for action to increase transparency in the calculation of cross-zonal capacity, with a view to maximising use of existing capacity and avoiding undue limitation and curtailment of cross-border capacity for the purposes of solving internal congestions."

[52] Joint ACER-CEER response to European Commission's Consultation on a new Energy Market Design, October 2015

2.3. Improving the coordination of Transmission System Operation

2.3.1. *Summary table*

Objective: Stronger coordination of Transmission System Operation at a regional level				
	Option 0	Option 1	Option 2	Option 3
Description	BAU Limit the TSO coordination efforts to the implementation of the new Guideline on Transmission System Operation (voted at the Electricity Cross Border Committee in May 2016 and to be adopted by end-2016) which mandates the creation of Regional Security Coordinators (RSCs) covering the whole Europe to perform five relevant tasks at regional level as a service provider to national TSOs.	Enhance the current set up of existing RSC by creating Regional Operational Centers (ROCs), centralising some additional functions at regional level over relevant geographical areas and delineating competences between ROCs and national TSOs.	Go beyond the establishment of ROCs that coexist with national TSOs and consider the creation of Regional Independent System Operators that can fully take over system operation at regional level. Transmission ownership would remain in the hands of national TSOs.	Create a European-wide Independent System Operator that can take over system operation at EU-wide level. Transmission ownership would remain in the hands of national TSOs.
Pros	Lowest political resistance.	Enlarged scope of functions assuming those tasks where centralization at regional level could bring benefits A limited number (5 max) of well-defined regions, covering the whole EU, based on the grid topology that can play an effective coordination role. One ROC will perform all functions for a given region. Enhanced cooperative decsion-making with a possibility to entrust ROCs with decision making competences on a number of issues.	Improved system and market operation leading to optimal results including optimized infrastructure development, market facilitation and use of existing infrastructure, secure real time operation.	Seamless and efficient system and market operation.
Cons	Suboptimal in the medium and long-term.	Could find political resistance towards regionalisation. If key elements/geography are not clearly enshrined in legislation, it might lead to a suboptimal outcome closer to Option 0.	Politically challenging. While this option would ultimately lead to an enhanced system operation and might not be discarded in the future, it is not considered proportionate at this stage to move directly to this option.	Extremely challenging politically. The implications of such an option would need to be carefully assessed. It is questionable whether, at least at this stage, it would be proportionate to take this step.
Most suitable: Most suitable option(s): Option 1 (Option 2 and Option 3 constitute the long-term vision)				

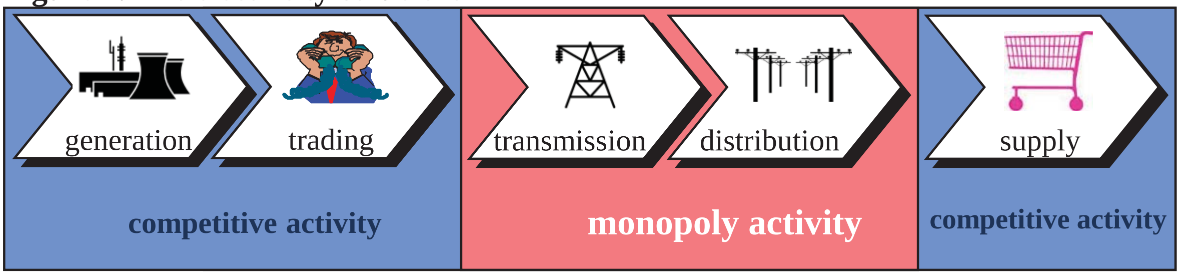
2.3.2. *Detailed description of the baseline*

Operation of the transmission system

Traditionally, prior to the restructuring of the energy sector, most electricity utilities were run by national and very often state-owned monopolies. These were in most cases vertically integrated utilities that owned and operated all the generation and system assets in their allocated territories.

The adoption and implementation of the three energy packages have led to the introduction of competition in the generation and supply of electricity, the introduction of wholesale electricity markets for the trading of electricity as well as to different degrees of unbundling of transmission and distribution activities, which constitute monopoly activities.

Figure 1. The electricity value chain



Source: European Commission

The fact that the activity of electricity transmission system operation is mostly national in scope derives from the past existence of vertically integrated utilities that were active throughout the whole electricity supply value chain. Following the restructuring of the electricity sector, Member States naturally tasked TSOs with the responsibility of ensuring the secure operation of the electricity system at national level.

This approach is currently reflected in the EU legislation. Article 12 of the Electricity Directive establishes that each TSO shall be responsible, *inter alia*, for managing the electricity flows on the system, taking into account exchanges with other interconnected systems. The Commission Implementing Regulation establishing a guideline on electricity transmission system operation ('System Operation Guideline') specifies further this obligation and sets out a requirement on TSOs to ensure that their transmission system remains in the normal state and makes them responsible for managing violations of operational security[53].

Coordination of transmission system operation: shift from a voluntary approach to a mandatory framework

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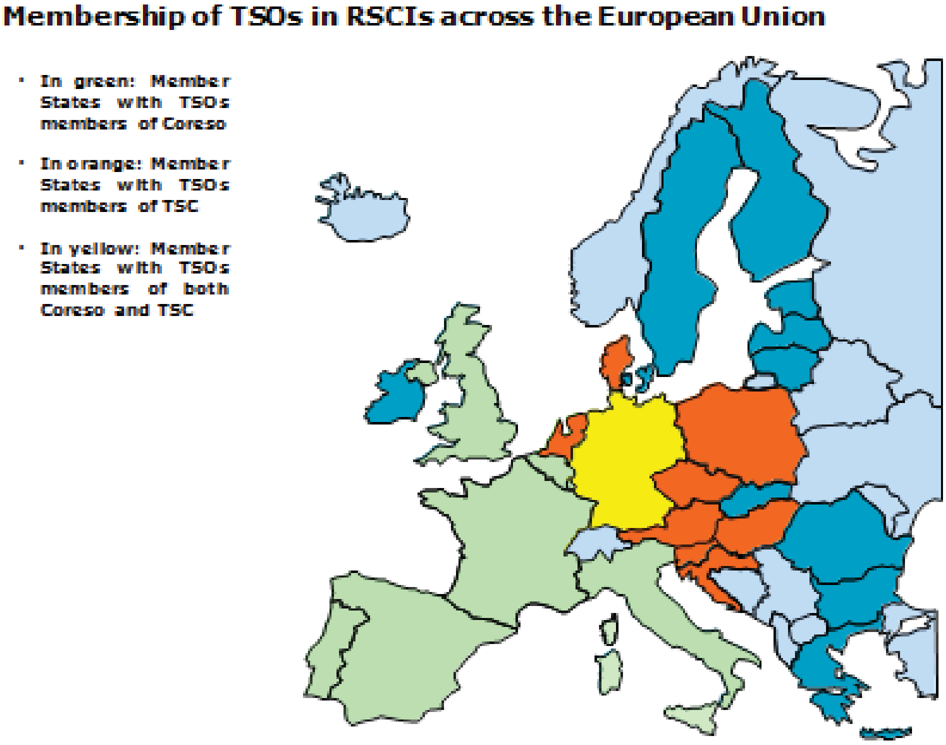
[53] The System Operation Guideline was voted on 4 May 2016 and is due to be adopted after scrutiny by the Council and the European Parliament. https://ec.europa.eu/energy/sites/ener/files/documents/SystemOperationGuideline%20final%28provisional%2904052016.pdf

Driven by the lessons learnt from the serious electrical power disruption in Europe in 2006, European TSOs have pursued enhancing further regional cooperation and coordination. To this end, TSOs voluntarily launched Regional Security Coordination Initiatives (RSCIs), entities covering a greater part of the European interconnected networks aiming at improving TSO cooperation. The main RSCIs in Europe are Coreso and TSC, both launched in 2008, followed by the ongoing development and establishment of additional RSCIs, such as SCC in Belgrade (launched in 2015) and an RSCI to be launched by Nordic TSOs by the end of 2017. Currently, RSCIs monitor the operational security of the transmission system in the region where the TSOs with membership in the RSCIs are established and assist TSOs proactively in ensuring security of supply at a regional level. By performing these functions, RSCIs provide TSOs with detailed forecasts of security analysis and may propose coordinated measures that TSOs may decide or not to implement.

In December 2015, all European TSOs except for SEPS a.s., the Slovakian TSO, signed a multi-lateral agreement to roll out RSCIs in Europe and to have them deliver core services to support the TSOs carry out their functions and responsibilities at national level.

R&D results: Tools for TSOs to deal with an increase in cross-border flows and variability of generation are being developed in European projects like ITESLA and UMBRELLA. They show that coordinated operational planning of power transmission systems is necessary to cope with increased uncertainties and variability of (cross-border) electricity flows. These tools help decrease redispatching costs and the available cross-border capacity and flexibility while ensuring a high level of operational security.

Figure 2 State of play of the voluntary membership of TSOs in RSCIs across the European Union.



Source: European Commission (June 2016)

The voluntary establishment of RSCIs has been widely recognised as a positive step forward for the enhancement of cooperation of transmission system operation and has been recently formalised in EU legislation with the new System Operation Guideline.

Building on the emerging regional initiatives, the System Operation Guideline takes a further step and mandates the cooperation of EU TSOs at regional level through the establishment of maximum six regional security coordinators (RSCs) which will cover the whole EU to perform a number of relevant tasks at regional level as service providers to national TSOs.

The tasks that RSCs will perform pursuant to the System Operation Guideline are: (i) regional operational security coordination; (ii) building of the common grid model; (iii) regional outage coordination; and (iv) regional adequacy assessment. The task of capacity calculation follows from the implementation of the CACM Guideline and is not assigned in the System Operation Guideline. The draft Commission Regulation establishing a network code on Emergency and Restoration intends to extend the tasks of RSCs to include a consistency assessment of the TSOs' system defence plans and restoration plans.

The framework set out in the System Operation Guideline is meant to build on the existing voluntary initiatives of TSOs (Coreso and TSC). It requires each TSO to join a RSC and allows a degree of flexibility to TSOs to organise the coordination of regional system operation. In this regard, the TSOs of the different capacity calculation regions will have the freedom to appoint more than one RSC for that region and to allocate the tasks, as they deem most efficient, between them.

Based on the deadlines for implementation envisaged in the System Operation Guideline, RSCs should be fully operational around mid-2019.

Box 1: Support functions to be carried out by RSCs under the network codes and guidelines

Common grid model: The common grid model provides an EU-wide forecasted view of all major grid assets (generation, consumption, transmission) updated every hour. RSCs will participate in the iterative process starting from the collection of individual grid models prepared and shared by TSOs and aiming at delivering to all RSCs and TSOs, a common grid model adequate for the other functions listed below. This function is required at least for timeframes from year-ahead to intraday (year-ahead, week-ahead, day-ahead, and intraday).

Operational planning security analysis: RSCs will identify risks of operational security in any part of their regional area (mainly triggered by cross-border interdependencies). They will also identify the most efficient remedial actions (i.e., actions implemented by TSOs aimed at maintaining or returning the electricity system to the normal system state) in these areas and recommend them to the concerned TSOs, without being constraint by national borders. This function covers at least the day-ahead and intraday timeframes.

Coordinated capacity calculation: RSCs will calculate the available electricity transfer capacity across borders, using flow-based (FB) or net transfer capacity (NTC) methodologies. These methodologies aim at optimising cross-border capacities while ensuring security of supply. This function is carried out at least on the D-2 (for day-ahead capacity allocation) and D-1/ intraday (for intraday capacity allocation) timeframes.

Short and very short-term adequacy forecasts: RSCs will provide TSOs with consumption, production and grid status forecasts from the day-ahead up to the week-ahead timeframe. In particular, RSCs will perform a regional check/update of short/medium term active power adequacy, in line with agreed ENTSO-E methodologies, for timeframes shorter than seasonal outlooks. This function is carried out week-ahead (until day-ahead only if scarcity is detected or if there are changes in relevant hypotheses compared to week-ahead).

Outage planning coordination: This function consists in creating a single register for all planned outages of grid assets (overhead lines, generators, etc.). RSCs will identify outage incompatibilities between relevant assets whose availability status has cross-border impact and limit the pan-European consequences of necessary outages in grid and electricity production by coordinating planning outages. RSCs will carry out this function in the year-ahead timeframe with updates up to week-ahead (on TSO requests).

Consistency assessment of the TSOs' system defence plans and restoration plans: RSCs will assist TSOs in ensuring the consistency of the system defence plans and restoration plan.

2.3.3. *Deficiencies of the current legislation*

The regional TSO cooperation model resulting from the adoption of electricity network codes and guidelines constitutes a positive development compared to the existing voluntary cooperation. However, as explained below, this step, while being effective in the short-term, is not sufficient in the medium and long-term.

The unprecedented changes concerning the integration of the European electricity markets and the European agenda for a strong decarbonisation of the energy sector, resulting in increasingly higher shares of decentralized and often intermittent renewable energy sources, have made the operation of the national electricity systems much more interrelated than in the past.

The recently voted System Operation Guideline has not entered into force and been implemented yet. Nonetheless, as highlighted in pp 32-33 of the Evaluation, the challenges the EU power system will be facing in the medium to long-term are pan-European and cannot be addressed and optimally managed by individual TSOs, rendering the current legal framework concerning system operation not adapted to the reality of the dynamic and intermittent nature of the future electricity system and putting into question whether the mandated cooperation of TSOs via RSCs is fit for purpose in the post 2020 context.

First, the functions envisaged for RSCs in the System Operation and in the CACM Guideline will not suffice in the medium to long-term as there is an increasing need for electricity systems to be operated on a regional basis. Furthermore, there is room to enlarge the scope of functions that would increase the efficiency of the overall system, if performed at regional level.

Second, the geographical scope of RSCs set out in the System Operation Guideline could not be efficient in the post 2020 context. RSCIs have grown organically with political considerations in mind, rather than following criteria solely based on the technical operation of the grid. The degree of flexibility envisaged in the System Operation Guideline will allow TSOs to maintain that *status quo*, undermining the goal of having a regional entity that oversees system and market operation in the region. **Figure 2** representing the current membership of TSOs in RSCIs across the Union reflects this situation (e.g., membership of TenneT NL, the TSO of the Netherlands, in TSC as opposed to Coreso). The coordination with other regional groupings of TSOs deriving from the implementation of other network codes and guidelines is also an issue. For example, given the degree to which the grid is meshed in the CWE and CEE regions, it is virtually impossible to draw permanent lines dividing the regions and still respect the electrical interdependencies. Hence, the presence of two RSCIs (Coreso and TSC) for this region does not seem the optimal solution to play an effective coordination role.

Third, the implementation of the System Operation Guideline will entail that RSCs will play an increasingly important support role for TSOs. However, the full decision-making responsibility will remain with TSOs who will have to do the grid planning while taking into consideration also new options to grid extensions (such as energy storage). RSCs will not have executive powers and their activities will be limited to providing planning services to individual TSOs, who can accept or reject those services and who will retail full control of and accountability for the planning and operation of their individual networks. For example, when deciding about the commercial cross-border capacities in a given region which are already calculated at regional level, the decision taken by RSCs are non-binding meaning that they can be considered as an input that can be changed by TSOs based on national interest (e.g. in case of scarcity of supply in one country the TSO might be tempted to reduce their export capacities but this might not be the best decision from a regional system security perspective) or due to constraints in the national legal framework. In this regard, the rejection of a recommendation by a TSO would suffice to put in question the overall set of recommendations issued by a RSC. For example, if in a recommendation for an optimal set of remedial actions a given TSO did not agree, this would imply the whole recalculation of remedial actions for the region since such measures are usually interdependent. There is additional evidence pointing out to this problem. The ACER market monitoring report 2015 (to be published in 2016) remarks that there are strong indications that during the capacity calculation process TSOs resort to unequally treating internal and cross-zonal flows on their networks.

To conclude, while the enhanced regional TSO cooperation resulting from the adoption of electricity network codes and guidelines constitutes a positive step forward, it is important to note that it will not allow realising the full potential of these regional entities in the medium to long-term. If the benefits of market integration are to be fully realised, TSOs will have to cooperate even more closely at regional level. This will require adjusting the way in which the operation of the electricity system will be managed under the System Operation Guideline.

2.3.4. *Presentation of the options*

Option 0 - BAU

Option 0 would be to stop the coordination efforts at this stage and limit it to the progress achieved with the implementation of the System Operation Guideline.

The upcoming RSCs will have the following features:

i. Functions. Five main functions[54] will be performed by the upcoming RSCs as service providers to national TSOs under the network codes and guidelines (see **Box 1** above for a more detailed explanation of each of these functions).

   a. Coordinated Security Analysis (including Remedial Actions-related analysis)
   b. Common Grid Model Delivery
   c. Outage Planning Coordination
   d. Short and Very Short Term Resource Adequacy Forecasts
   e. Coordinated Capacity Calculation

   The addition of new functions would mainly depend on the voluntary initiative of TSOs, which in some instances could lead to inefficient outcomes given that they would not always have the "regional" perspective in mind but rather their own interest, particularly given the flexibility at the time of defining the geographical scope.

   Geographic scope. While RSCs will give full coverage across the EU, the size and composition of the regions where they will be established may not always be defined having the technical operation of the grid in mind. Business and political criteria could also play a role. In particular, TSOs in a region would continue having flexibility to decide which RSC provides a given service (including new ones developed voluntarily) to that region. This would allow a given region to get services from different RSCs. While this has been accepted as a valid compromise in the short-term, it undermines the goal of having a regional entity with enhanced overview over system and market operation in the region.

[54] Six functions with the adoption of the Emergency and Restoration network code *('Consistency assessment of TSOs' system defence plans and restoration plans').*

ii. Decision-making responsibilities. The upcoming RSCs will not have any decision-making powers but a purely advisory role. The responsibility for system operation will remain with TSOs at national level. The fact that RSCs issue recommendations means that ultimately an individual TSO may be constrained by the national framework and reject the implementation of such recommendation, against the interest of all the other TSOs of the region. Hence, the set up of the RSC being able to provide an added value at regional level would be compromised. For example, as described above, if in a recommendation for an optimal set of remedial actions a given TSO did not agree, this would imply the whole recalculation of remedial actions for the region since these measures are usually interdependent.

iii. Institutional layout/governance. The interaction between the RSCs, NRAs, TSOs, ACER and ENTSO-E would remain as set out in the System Operation Guideline. Essentially, TSOs and NRAs would continue to be responsible for the direct implementation and oversight of RSCs at national level. ACER and ENTSO-E would remain responsible for ensuring the cooperation of NRAs and TSOs at EU level, respectively.

Option 0+: Non-regulatory approach

Stronger enforcement would not suffice to address the needs of the electricity system regarding stronger TSO cooperation at regional level.. As in option 0, any progress beyond the framework in the System Operation Guideline and the application of other network codes would depend on the voluntary initiatives of TSOs. However, the voluntary initiatives would be limited due to the constraints resulting from differing legislation at national level. Hence, stronger enforcement or a voluntary approach is not a possible option.

Option 1: Enhance the current set up of existing RSCs by creating ROCs, centralising some additional functions over relevant geographical areas and optimising competences between ROCs and national TSOs

Option 1 would aim at enhancing the current set up of existing RSCs by creating ROCs. ROCs are not meant to substitute TSOs but to complement their role at regional level. This option would set out a number of basic elements in legislation but allow flexibility to TSOs to work out the details on how the ROCs will function and perform their tasks. ROCs will present the the following features:

i. Functions. Enlarged scope of functions, assuming new tasks where centralization at regional level could bring benefits. These functions would not cover real time operation which would be left solely in the hands of national TSOs. In addition to the functions emanating from existing network codes and guidelines (see **Box 1**), these functions would be:

   a. Solidarity in crisis situations: Management of generation shortages; Supporting the coordination and optimisation of regional restoration
   b. Sizing and procurement of balancing reserves
   c. Transparency: Post-operation and post-disturbances analysis and reporting; Optimisation of TSO-TSO compensation mechanisms
   d. Risk-preparedness plans (if delegated by ENTSO-E)

e. Training and certification (if delegated by ENTSO-E)

ii. Geographic scope. A limited number of well-defined regions, covering the whole EU. TSOs establishing the ROCs will need to decide the scope of these regions based on technical criteria (e.g. grid topology) to ensure that they can play an effective coordination role. In contrast to what is currently in the System Operation Guideline, each ROC would perform all functions for a given region. Larger regions could include, if necessary, back-up centres and/or sub regional desks when for example some functions would require specific knowledge of smaller portions of the grid.

iii. Cooperative decision-making. ROCs would have an enhanced advisory role for all functions. In order to respect to the maximum possible extent the regional recommendations, TSOs should transparently explain when and why they reject the recommendation of the ROC. Given that a role limited to issuing recommendations may lead to sub-optimal results as regards the performance of some of the functions[55], decision-making powers could be entrusted to ROCs for a number of relevant issues (i.e., remedial actions, capacity calculation) either directly by a Regulation or subsquentely by mutual agreement of the NRAs or Member States overseeing a certain ROC. By optimising decision-making responsibilities between ROCs and national TSOs the seamless system operation between the ROCs and the TSOs would be ensured.

iv. Institutional layout/governance. Enhanced cooperation between TSOs would be accompanied by an increased level of cooperation between regulators and governments as well as by an increased oversight from ACER and ENTSO-E.

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[55] This sub-optimal situation would derive from the fact that the rejection by a single TSO of the recommendation issued by the ROC would put in question the overall set of recommendations.

Box 2: Additional functions performed by ROCs under Option 1

- **Solidarity in crisis situations:**
  - *Management of generation shortages*. ROCs would optimise the generation park in a region while **attempting** to increase transmission capacity to the Member State which suffers generation shortage. The aim of this function is to avoid load cuts (energy non served situations) in a country while other countries still optimise the market and/or enjoy high generation margins.
  - *Supporting the coordination and optimisation of regional restoration*. ROCs would recommend the regional necessities during restoration (e.g., resynchronisation sequence of large islands in case of the split of a synchronous area).
- **Sizing and procurement of balancing reserves:**
  - *Regional calculation of daily balancing reserves*. ROCs would carry out regional sizing of daily balancing reserves (disregarding political borders and considering only technical limitations related to geographical dispersion of reserves) on the basis of common probabilistic methodologies (i.e. balancing reserve needs based on different variables such as RES generation forecast, load fluctuations and outage statistics).
  - *Regional procurement of balancing reserves*. ROCs would create regional platforms for the procurement of balancing reserves, complementing the regional sizing of balancing reserves.
- **Transparency:**
  - *Post operation and post disturbances analyses and reporting*. ROCs would carry out centralised post-operations analyses and reporting, going beyond the existing ENTSO-E Incidents Classification Scale (ICS).
  - *Optimisation of TSO-TSO compensation mechanisms*. ROCs would administer common money flows among TSOs, such as Inter-TSO Compensation (ITC), congestion rent sharing, re-dispatching cost sharing, cross-border cost allocation (CBCA). Furthermore, ROCs should propose improvements to the schemes based on technical criteria and aiming for the optimal overall incentives.
- **Risk-preparedness plans.** If delegated by ENTSO-E, the ROCs' function would be to identify the relevant risk scenarios in its region that the risk preparedness plans should cover. Based on ROCs' proposals, Member States would develop the plans. ROCs could organise crisis simulations (stress tests) together with Member States and other relevant stakeholders. During such crisis simulations the plans would be tested to check if they are suited to address the identified cross-border or regional crisis scenarios.
- **Medium term adequacy assessments:** if delegated by ENTSO-E, ROCs would complement the ENTSO-E seasonal outlooks with adequacy assessments carried out in a regional context where possible crisis scenarios (e.g. prolonged cold spell), including simultaneous crisis, should be identified and simulated.
- **Training and certification.** The network code on staff training and certification as foreseen in the ACER framework guideline on system operation is still pending. ROCs could cover functions related to trainings between TSOs as well as centralise of some trainings in issues related to cross-border system operation. Further, this function should allow regional training on simulators (IT system based on a relevant representation of the system, including networks, generation and load).

Option 2: Creation of Regional Independent System Operators

Option 2 would be to go beyond the establishment of ROCs that coexist with national TSOs and consider the creation of Regional Independent System Operators (RISOs) that can fully take over system operation at regional level.

RISOs would have the following features:

i. Functions. RISOs would have an enlarged scope of functions compared to ROCs. In addition to the functions under Option 1, RISOs would also be responsible for real time operation of the electricity system (e.g., operation of real time balancing markets) and for infrastructure planning. Infrastructure related functions could include for example the identification of the transmission capacity needs: proposing priorities for network investments based on the long-term resource adequacy assessment, the situation in the interconnected system and identified structural congestions, while considering an interconnected system without political borders.

ii. Geographic scope. The scope of RISOs would be the same as for ROCs.

iii. Decision-making responsibilities. All system operation functions would be performed by the RISOs, which would have decision-making powers. Existing TSOs would remain as transmission owners and solely operate physically the transmission assets and provide technical support to RISOs (e.g., collection and sharing of data).

iv. Institutional layout/Governance. Additional changes in the institutional framework would be required to enable the RISO approach. For example, it would be necessary to amend the powers and competences of TSOs, of regulatory authorities and of ACER in order to ensure the appropriate oversight of these entities. It would also be necessary to consider aspects such as the financing of RISOs or the applicability of unbundling rules.

Option 3: creation of a European-wide Independent System Operator

Option 3 would imply the creation of a European-wide Independent System Operation (EU ISO) that would take over system operation at EU-wide level.

This entity would have the following features:

i. Functions. The functions would be the same as those proposed under Option 2 for RISOs.

ii. Geographic scope. The EU ISO would be responsible for system operation at EU-wide level.

iii. Decision-making responsibilities: The EU ISO would perform all system operation functions and hence would have decision-making powers. TSOs would solely operate physically the transmission assets and provide technical support to RISOs (e.g., collection and sharing of data).

iv. Institutional layout/Governance: significant changes would be required in the institutional framework to enable the creation of an EU ISO and an effective oversight of its acitivities. It would be necessary to amend the powers and competences of TSOs, of regulatory authorities and of ACER. It would also be necessary to consider aspects such as its financing, monitoring of its performance, etc.

2.3.5. *Comparison of the options*

The following Section provides a comparison of the options described above based on the four main elements identified: (i) functions; (ii) geographical scope; (iii) decision-making competences; and (iv) institutional layout/ governance. Given that only a few studies have been carried out on this field, the assessment of the options will be mainly qualitative, based on the feedback received from stakeholders and on the content of the studies published to date, and providing figures where they exist.

(i) Functions

It is not possible to provide a complete quantification of the costs and benefits of each of the Options as regards the set of functions to be performed at regional or EU level given that few studies have assessed these costs and benefits. However, the insights from several previous studies cover the potential benefits of a supranational approach to system operation.

Table 1 Functions that would be covered under each of the options

	RSCs (Option 0)	ROCs (Option 1)	RISOs/EU ISO (Options 2 and 3)
System Operation			
Coordinated Security Analysis (including Remedial Actions-related analysis)	x	x[56]	x
Common Grid Model Delivery	x	x	x
Outage Planning Coordination	x	x	x
Short and Medium Term Resource Adequacy Forecasts	x	x	x
Regional system defence and restoration plans	x	x	x
Centralised post operation analyses and reporting		x	x
Training and certification		x	x
Market Related			
Coordinated Capacity Calculation	x[57]	x[58]	x
Coordinated sizing and procurement of balancing reserves		x	x
Network Planning			
Identification of the transmission capacity needs			x
Technical and economic assessment of CBCA cases			x
Administration of TSO-TSO compensation mechanisms (ITC, congestion rent sharing, redispatching cost sharing, CBCA)		x	x
Risk-preparedness			
Support Member States on development of risk preparedness plans		x	x

Source: DG ENER

56 It could include decision-making powers.

57 The CACM Guideline provides for regional capacity calculators. However, following the commitments of ENTSO-E, this role could be already assumed for RSCs.

58 It could include decision-making powers.

Table 2 Qualitative estimate of the economic impact of the Options:

	Option 0: RSC approach	**Option 1**: ROC approach	**Option 2:** RISO approach	**Option 3:** EU ISO approach
Economic Impact				
Enhancing security of supply by minimising the risk of blackouts[59] [60]	0/+	+	++	++
Lowering costs through increased efficiency in system operation[61] [62] [63]	0/+	++	+++	+++
Maximising transmission capacity offered to the market[64]	0/+	++	+++	+++

59 The financial and social impact of wide area security breaches is enormous: as estimated by ENTSO-E, the economic impact of wide area security breaches could be really important; the cost of a 20 GW load disconnection during a large brownout is estimated to 800 million euros per hour (i. e. 40 euros / kWh). Blackouts have an even higher impact. This provides quantified insight into the importance of optimised emergency and restoration efforts with a central coordination of locally required efforts.

60 ENTSO-E (2014), "*Policy Paper on Future TSO Coordination for Europe*", Retrieved from: https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/141119_ENTSO-E_Policy_Paper_Future_TSO_Coordination_for_Europe.pdf

61 The management of generation shortages should increase the regional social welfare as a result of a decrease of financial losses that would otherwise result from disconnection of load. It would also increase solidarity and promote trust in the internal energy market.

62 Also, some of the benefits will derive from the optimisation of training and certification. TSOs will gain more practical experiences using same tools, practicing common scenarios and sharing best practices. This should lead to faster system restoration and more efficient tackling of regional-wide system events.

63 A regional approach to adequacy assessment enhances the use of cross-border connections at critical moments, resulting in an overall less required generating capacity in Europe. The enhancement is expected to increase with increasing variable renewable energy in the system. The IEA mentions a benefit of 1.4 euros/MWh based on the study of Booz & co. An example for regional adequacy assessment is provided by the Pentalateral Energy Forum.

64 A supranational approach (moving local responsibilities to ROCs) to capacity calculation can bring significant welfare benefits due to more efficient use of infrastructure and the consequent benefits coming from the improved arbitrage between price zones. The CACM Guideline Impact assessment estimates the welfare gains of a supranational approach to flow-based capacity calculation to be in the region of 200-600 million euros per year. These benefits would only partially materialise (20% of welfare gains would not be realised) on a voluntary basis, leaving significant parts of the capacities used in a suboptimal manner.

Reducing the need of remedial actions by coordinating and activating in a coordinated way redispatching[65] [66]	0/+	++	+++	+++
Minimising the costs of balancing provision by taking a more coordinated approach towards the sizing of balancing reserves[67] [68] [69]	0/+	++	+++	+++
Optimisation of infrastructure planning[70]	0	0	++	+++

65 Significant benefits are expected by the fact that enhanced TSO cooperation minimises the need for redispatching, especially costly emergency actions. To illustrate, Kunz et al. quantified the benefits of coordinating congestion management in Germany: in case each TSO is responsible to relief overflows within its own zone with its own resources, which reflects the current situation in Germany closest, redispatch costs of 138.2 million euros per year accrue. Coordinating the use of transmission capacities renders costs of 56.4 million euros per year. As a benchmark, one single unrestricted TSO across all zones would have to bear redispatch expenditures of 8.7 million euros per year. Kunz et al. also quantified the benefits of coordinating congestion management cross-border (for the region comprising Germany, Poland, Czech Republic, Austria, Slovakia): without coordination, total costs of congestion management amount to 350 million euros per year, they decrease to 70 million euros per year for optimised congestion management (including remedial actions and flow-based cross-border capacity allocation).

66 Kunz et al., *"Coordinating Cross-Country Congestion Management"*, DIW Berlin , 2016 and Kunz et al., *"Benefits of Coordinating Congestion Management in Germany"*, DIW Berlin, 2013

67 As regards the regional sizing and procurement of balancing reserves, the added value of this function is gain in social welfare due to decreased size of needed balancing reserves and gains in techno-economic optimisation of the procurement of the needed balancing reserves. Shared balancing has cost advantages residing from netting of imbalances between balancing areas and from shared procurement of balancing resources or reserves. This can be based on exchanging surpluses or based on a shared or common merit order for all balancing resources. Mott Macdonald mentions potential overall benefits from allowing cross-border trading of balancing energy and the exchanging and sharing of balancing reserve services of the order of 3 billion euros per year and reduced (up to 40% less) requirements for reserve capacity. This is for a European electricity supply system with roughly 45% renewable energy.

68 Mott MacDonald (2013), "*Impact Assessment on European Electricity Balancing Market*" Retrieved from: https://ec.europa.eu/energy/sites/ener/files/documents/20130610_eu_balancing_master.pdf

69 According to the study carried out by Artelys on Electricity balancing: market integration & regional procurement, regional sizing and procurement of reserves by ROCs could lead to benefits of 2.9 billion Euros (compared to 1.8 billion euros benefits from national sizing and procurement). An EU-wide sizing and procurement of balancing reserves would lead to benefits of 3.8 billion Euros.

70 The added value as regards the identification of the transmission capacity needs at regional level is the provision of neutral, regional view of investments needs. The industry represented by Eurelectric claims that "*Network investment planning and the coordination of TSOs' network investment decisions by the RISOs are the next natural steps.*" As regards the technical and economic assessment of cross-border cost allocation (CBCA) cases, benefits are expected from higher efficiency and quicker processes for important transmission infrastructure projects.

Enhancing transparency[71]	0	0/+	+	+
Costs of implementation72	0/-	-	---	----
Other impacts				
Administrative impacts/ governance	0/-	-	--	---

Source: DG ENER.The assumptions in this table are based on the studies existing in this field as well as on the feedback received from stakeholders in their response to the public consultation and from estimations concerning the resources of RSCs and ENTSO-E.

In sum, as illustrated in Table 2, the set of functions in **Option 0** will entail limited costs and benefits, since many of these functions are already carried out by RSCIs in their supporting role to TSOs. The implementation of the System Operation Guideline and establishment of ROCs will not involve significant changes to the *status quo*. The set of additional functions under **Option 1** will entail efficiency gains and increase social welfare that will derive from providing additional functions to ROCs to be optimised at regional level (as opposed to national level)[73]. In addition, it will entail costs related to the shift of these functions from national to regional level (e.g., development of processes and tools at regional level) and will have an impact on the institutional structures (i.e., need to adapt the institutional framework to ensure the proper monitoring of implementation of the functions). **Option 2** will present additional gains and costs compared to Option 1. The benefits will result from the more integrated operation of the system at regional level as well as from the additional set of functions to be performed by RISOs, which will comprise real-time operation of the electricity system. The costs will derive from the need to develop new methodologies, processes and tools to ensure the performance of these additional functions and the need to adapt the current oversight of

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71 As regards the optimisation of TSO-TSO compensation mechanisms, the added value is increased transparency and step-by-step optimisation of the schemes, resulting in more cost-efficient operation of the system. This is supported by Eurelectric which states that *"Regarding coordination of network investment decisions, this would require the development of mechanisms for inter-TSO money flows. Development of inter-TSO money flows will also allow efficient coordinated redispatching, as requested by the CACM Guideline. This is considered to be a key element for enabling efficient intraday capacity (re-)calculation"*. See Eurelectric, "*Develop a regional approach to system operation*", June 2016. As regards, post operation and post disturbances analyses and reporting, the added value is increased transparency, better regional understanding and improvement process, as well as and potential efficiency gains.

72 The costs of establishing ROCs, RISOs or an EU ISO are estimated to range between 9.9 and 35.6 million EUR per entity. See "*Electricity Balancing*" Artelys (2016). The study does not provide a break out of the costs between Options 1, 2 and 3 but assumes that the costs will vary depending on the functions and responsibilities attributed to these entities.

73 For instance, the management of generation shortages based on seasonal outlooks should increase the regional social welfare as a result of a decrease of financial losses that would otherwise result from disconnection of load.

the performance of these functions. **Option 3** is the option that will entail most economic gains (deriving from the efficiencies of performance of the functions at EU level) and also most implementation costs.

(ii) Geographic scope

In the current context of the rolling out of RSCs (**Option 0**), there will be certain flexibility for TSOs to decide which coordinator provides a given service to a region. This could allow a given region to get services from different providers. While this is an acceptable compromise in the short and medium term, it partly undermines the goal of having a regional entity with enhanced overview over system operation and market operation in the region. In addition, although there will be full European coverage by the RSCs (with a maximum number of 6), the size and composition of the regions is not always defined having the technical operation of the grid in mind. Business and political criteria play also a role in it.

Option 1 would allow ROCs to play an effective coordination role leading to enhanced system security and market efficiency – given that the ROCs would be able to optimise the operations over larger regions[74]. In contrast with Option 0, the regions would be defined according to market and system operation criteria (e.g. grid topology). Having a limited number of ROCs will also bring in savings in developing system operation tools. However, there would be costs related to the need to adapt further the geographical scope from RSCs to ROCs but this could be mitigated through a carefully planned implementation. In Option 1, ROCs would have the possibility to include back-up centres that ensure that one centre can take over from the other if a problem arises and/or include sub-regional desks for looking at issues where a more detailed assessment is needed. This could for example be the case if a ROC is created for the Continental Europe synchronous area (or at least for Central Western Europe and Central Eastern Europe) as a natural evolution of the existing Coreso and TSC coordinators – in this case, it could be natural to have a set up with two locations within a ROC (e.g. Munich and Brussels, if current coordinadors were to keep existing locations).

The benefits and shortcomings of **Option 2** would be similar to those of Option 1 as the geographical scope of both options would be the same.

Option 3 would entail that the EU ISO is responsible for performing all the functions at EU level. This approach would lead to efficiency gains, as it would no longer be necessary to ensure the coordination and cooperation between entities at regional level and all the functions could be performed seamlessly. However, it is questionable whether from a technical point of view, at this stage, a single entity would be capable of carrying out all these functions at EU level even if it envisages setting up sub-regional desks for the more detailed assessment of regions.

(iii) Decision-making competences

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[74] This would also pave the way for a further long term evolution towards Regional Independent System Operators.

In **Option 0**, RSCs have a purely advisory role i.e. the recommendations that they issue can be overriden by TSOs[75]. This would be the option less politically sensitive. However, this can potentially lead to inefficient outcomes. For example, when deciding about the commercial cross-border capacities in a given region which are already calculated at regional level, the decision taken by RSCs in the form of recommendations are non-binding. These decisions can be considered as an input that can be rejected by TSOs based on national interest (e.g. in case of scarcity of supply in one country the TSO might be tempted to reduce their export capacities but this might not be the best decision from a regional system security perspective) or due to constraints in their national framework (e.g., in the case of cross-border remedial actions, a TSO may be obliged to reject the recommendations issued by the ROC given that the national framework requires a different order of implementation of remedial actions).

In **Option 1** ROCs would have an enhanced advisory role for all functions. Under this option, ROCs could be entrusted with certain decision-making competences (as opposed to a pure service provision role) to avoid the possibility of regional optimisation being lost due to national constraints. This approach is likely to lead to more efficient outcomes since there would be a margin for overcoming obstacles deriving from the national framework (e.g. remedial actions, capacity calculation). In the case of the example above, when deciding about the commercial cross-border capacities in a given region which are already calculated at regional level, the decisions taken by ROCs could be final and binding. Whilst this option is likely to bring more efficient outcomes, it is also likely to be more politically controversial, especially with TSOs and Member States. However, other stakeholders have expressed support for this option[76]. This could be done either directly enshrining the functions in legislation or subsequently by mutual agreement of the NRAs overseeing a certain ROC.

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[75] Indeed, coordination between TSOs through RSCs could be successful if the national frameworks were harmonised. However, since national frameworks may differ significantly, voluntary coordination is not likely to be optimal in the medium term.

[76] Eurelectric has recently pointed out that *"A step-wise regional integration of system operation and of planning tasks relevant to cross-border trade therefore needs to happen. Such a process should build upon the ongoing establishment of RSCs, which are executing a certain number of system operation tasks on behalf of the national TSOs and could be a step towards gradually allocating the responsibility for those tasks to regional entities"*. Eurelectric, *"Develop a regional approach to system operation"*, June 2016. Also, in response to the Commission Public Consultation on a new energy market design, Acciona emphasised that *"system operation should be coordinated at the same level as markets are, to efficiently manage electricity systems as an integrated whole. Therefore, a regional responsibility for system security should gradually replace national responsibilities"*. Also in its response to the Public Consultation, Engie submitted that *"current national responsibility for system operation indeed hampers cross-border cooperation and is not mimicking the progress made on side of market integration: different capacity calculation in the flow based approaches are leading to lower capacity"* and that it *"favours closer cooperation of TSOs and RSCs taking over new functions progressively (eventually replacing national TSOs in those functions). Stepwise approach is needed."* In its response to the Public Consultation, Business Europe has stated that *"establishing regional system operators, based on a costs-benefits analysis, could be a first step towards more operational coordination of TSOs in the future"*.

In **Option 2** with RISOs that can fully take over system operation at regional level, all functions carried out by RISOs would be binding since they would fully replace the functions performed at national level. Entrusting decision making powers to RISOs would be justified based on the fact that system operation decisions might span well beyond the area of a single TSO and affect the whole system. This would be the basis for a regional system operation[77]. However, this option would be extremely sensitive politically and would likely be rejected by many Member States.

Option 3 would require entrusting the performance of the functions and associated decision-making powers to a single entity, the EU ISO, who would take binding decisions. This option would set the basis for a truly European operation of the electricity system. While there would be additional efficiency gains compared to those resulting from Option 2 (e.g., it would no longer be necessary to ensure the coordination of operations of a number of entities at regional level), it is unclear whether this option is technically feasible at this stage. Option 3 would also be politically unacceptable.

(iv) Institutional layout/Governance

Option 0 would not require significant institutional changes, as the interaction between RSCs, NRAs, TSOs, ACER and ENTSO-E would remain as set out in the System Operation Guideline. **Option 1** would require increasing the level of cooperation between NRAs and governments, as well as additional competences for ACER and ENTSO-E, to ensure the oversight of ROCs. **Options 2 and 3** would each require substantial changes to the institutional framework in order to encompass the switch of decision-making powers for system operation from a national to a regional or EU-wide level. The costs and speed of implementation would also increase for each of the options, being Option 3 the most costly and most timely.

(v) Conclusion of evaluation

The Table below provides a qualitative comparison of the Options in terms of their effectiveness, efficiency and coherence of responding to specific criteria.

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[77] In this regard, Eurelectric has highlighted that *"A truly regional system operation can however only be based on a regional decision-making structure and a single operational framework. Establishing regional integrated system operators performing system operation and planning tasks in all regions should therefore be the end goal to allow for more operational coordination of TSOs"*. Eurelectric, "*Develop a regional approach to system operation*", June 2016

Table 1: (The assumptions in this table are based on the feedback received from stakeholders in their response to the public consultation and from additional submissions from ACER).

Criteria	Option 0: BAU	Option 1: ROC approach	Option 2: RISO approach	Option 3; EU ISO approach
Quality	0/+ Progress remains limited due to zones not based on technical operation of the grid	+ More efficient as optimisation over zones based on technical operation of the grid	++ Very efficient because of enhanced system operation at regional level	+++ Most efficient because of seamless system operation at EU level
Speed of implementation	+ Can build upon established structures (RSCIs)	0 Can partially build upon established structures; change in geographical scope and functions	-- Can partially build upon established structures but it will require a substancial centralization at regional level; change in geographical scope of functions; it would require a substantial amount of time for implementation.	--- Cannot build on established structures. Substantial change in geographical scope of functions. It would require a substantial amount of time for implementation
Use of established institutional processes	++ Can build upon established structures (no decision-making responsibility)	- Requires building up new structures/ processes (possibly some decision-making responsibility)	-- Requires building up new structures/ processes (decision-making responsibility for all regional relevant functions)	--- Requires building additional structures and processes that are adapted for the operation of this entity at EU level (decision-making responsibilities for all functions at EU level)
Secure operation of the network	0/+ Mandated cooperation; slightly reduced risk of blackout	+ Enhanced cooperation via ROCs; reduced risk of blackout	++ Integration via RISOs; significantly reduced risk of blackout	+++ Seamless operation at EU level; significantly reduced risk of blackout
Efficient organisational structure	- Sub-optimal organisational structure; a given region can get services from different providers	++ Efficient organisational structure can be created; all services for a region carried out by one company	+++ Efficient organisational structure can be created; all services for a region carried out by one company	+++ Efficient organisational structure can be created; all services at EU level carried out by a single company
Political sensitivity	0 Politically most acceptable as it represents the convergence achieved during discussions with Member States and stakeholders for the System	- Politically sensitive due to shift in decision-making responsibility for relevant functions	-- Extremely politically sensitive due to shift in decision-making responsibility	--- Politically unacceptable at this stage

	Operation Guideline			

In summary:

While **Option 0** will allow achieving some progress in terms of regional coordination which might be sufficient in the short to medium term, it risks falling short and being suboptimal in the post 2020 context with the subsequent negative consequences in terms of system security and market efficiency[78]. It would also affect the effectiveness of many of the other proposals of the market design initiative and be a missed opportunity to propose legislation on the field that can shape the EU power system in the future.

Option 1 is the preferred option to respond to the post 2020 challenges in system operation. Execution of the additional functions as outlined in Option 1 will lead to the ROCs approach, featuring benefits in efficiency and security, but also leading to increased needs for resources at regional level (data systems, experienced staff). Allowing ROCs to be entrusted with certain decision-making responsibilities (as opposed to a pure service provision role) will avoid the possibility of regional optimisation being lost due to constraints resulting from differences in the national frameworks. This option enhances the effectiveness of many other proposals of the market design initiative.

Option 2 and **Option 3** would constitute the most preferable options from the point of view of seamless system operation, efficiency and economic gains. While they should not be discarded as a direction that should be followed in the future, none of these options are considered proportionate at this stage. Moreover, the feasibility of Option 3 is questionable. Option 2 is supported by some stakeholders as a long-term goal[79].

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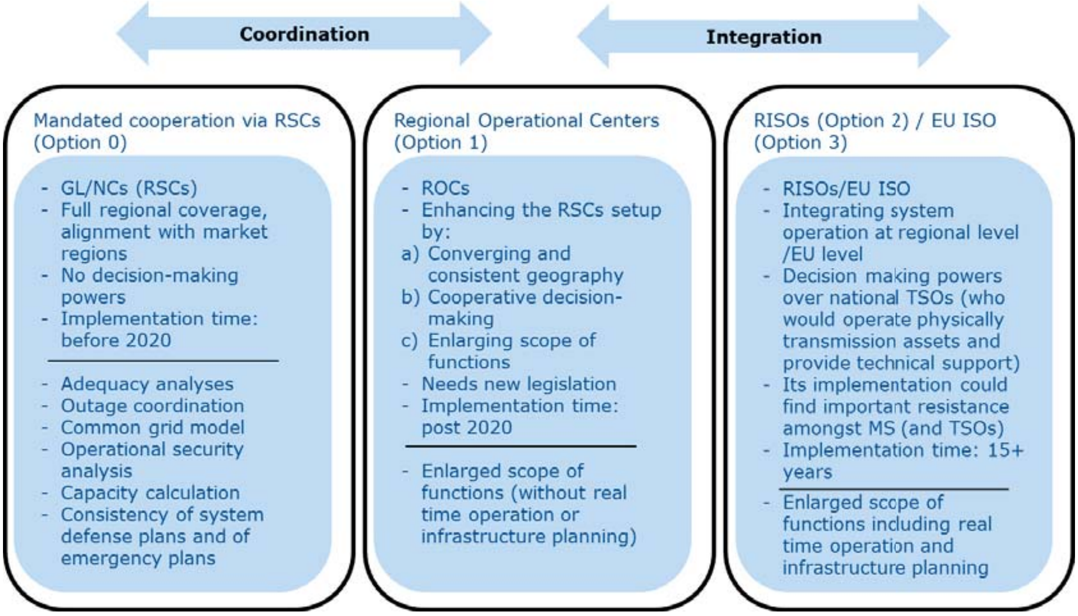
[78] Eurelectric shares this view and has recently stated that "*Current TSOs coordination initiatives such as RSCs are steps in the right direction. The harmonisation and integration requirements developed in the System Operation Guideline are nevertheless not ambitious enough. Indeed, these approaches remain mostly national with the aim to protect the autonomy of individual system operators. Most importantly, those initiatives do not fully equip system operators to cope with the challenges of a low-carbon power power system"*. Eurelectric, *"Develop a regional approach to system operation"*, June 2016

[79] For example, Eurelectric declares that *"A truly regional system operation can however only be based on a regional decision-making structure and a single operational framework. Establishing regional integrated system operators performing system operation and planning tasks in all regions should therefore be the end goal to allow for more operational coordination of TSOs"*. Moreover, it states that *"The transistion towards a truly integrated and decarbonised elecricity market will be more efficient if the electricity system is optimised on a regionla and ultimately a European basis (e.g. TSOs should operate the system as "one"). This will require a high degree of cooperation between system operators and the harmonisation of system operation rules. […] Establishing regional integrated system operators performing system operation and planning tasks in all regions should therefore be the end goal to allow for more operational coordination of TSOs"*. Eurelectric, "*Develop a regional approach to system operation"*, June 2016. In addition, in response to the Commission public consultation on a new energy market design, Fortum submitted that *"the goal should be that the market, in practice, sees only one TSO. It could be done by [an] European TSO or by current TSOs improving their cooperation"*.

Figure 3 below describes a stepwise approach for the implementation of the future ROCs



Source: Commission.

2.3.6. <u>*Subsidiarity*</u>

The subsidiarity principle is respected given that the challenges the EU power system will be facing in the post 2020 context are pan-European and cannot be addressed and optimally managed by individual TSOs. While the mandated TSO cooperation via the establishment of Regional Security Coordinators (RSCs) envisaged in the System Operation Guideline constitutes a positive step forward because they will play an increasingly important support role for TSOs, the full decision-making responsibility will remain with TSOs. This framework will however not suffice to address the reality of the dynamic and variable nature of the future electricity system, in which stressed system situations will become more frequent. This is why it would be required to make the concept of RSCs further evolve towards the creation of ROCs, centralising some functions over relevant geographical areas.

The creation of ROCs and allocation of competences to these entities would also be in line with the proportionality principle given that it does not aim at replacing national TSOs but rather at complementing the functions which have regional relevance and cannot be optimally performed in isolation any longer. The competences of ROCs will be limited to specific operational functions at regional level, for cross-border relevant issues in the high voltage grid and will exclude real-time operation.

2.3.7. <u>*Stakeholders' opinions*</u>

Based on the results of the Public Consultation, as concerns the proposal to foster regional cooperation of TSOs, a clear majority of stakeholders is in favour of closer cooperation between TSOs. Stakeholders mentioned different functions which could be better operated by TSOs in a regional set-up and called for less fragmentation in some important work of TSOs. Around half of those who want stronger TSO cooperation are also in favour of regional decision-making responsibilities (e.g. for Regional Security Coordinators). Views were split on whether national security of supply responsibility is an obstacle to cross-border cooperation and whether regional responsibility would be an option.

The participants to the European Electricity Regulatory Forum have also recently emphasised the need for closer cooperation between TSOs, enlarging the scope of functions and optimising the geographical coverage of regional centres. It recognised, however, that there were divering opinions as regards the delineation of responsibilities between regional centres and national TSOs and that further consideration was needed[80].

The creation of Regional Operational Centres will be likely seen with concern by TSOs and a large number of Member States which seem to consider that the currently foreseen cooperation via Regional Security Coordinators is fit for purpose. In particular, Member States are likely to oppose any step oriented to entrust regional structures with decision making powers under the assumption that security of supply is a national responsibility. Regarding the regions, Member States might prefer geographical dimensions based on governance rather than what would be optimal from a technical point of view.

[80] See Florence Forum conclusions of March 2016: https://ec.europa.eu/energy/sites/ener/files/documents/Conclusions%20-%20Florence%20Forum%20-%20Final.pdf

3. Detailed measures assessed under Problem Area I, option 1(c); Pulling demand response and distributed resources into the market

3.1. Unlocking demand side response

3.1.1. *Summary table*

Objective: Unlock the full potential of demand response			
Option O: BAU	Option 1: Give consumers access to technologies that allow them to participate in price based demand response schemes	Option 2: as Option 1 but also fully enable incentive based demand response	Option 3: mandatory smart meter roll out and full EU framework for incentive based demand response
Stronger enforcement of existing legislation that requires Member States to roll out smart meters if a cost-benefit analysis is positive and to ensure that demand side resources can participate alongside supply in retail and wholesale markets	Give each consumer the right to request the installation of, or the upgrade to, a smart meter with all 10 recommended functionalities. Give the right to every consumer to request a dynamic electricity pricing contract.	In addition to measures described under Option 1, grant consumers access to electricity markets through their supplier or through third parties (e.g. independent aggregators) to trade their flexibility. This requires the definition of EU wide principles concerning demand response and flexibility services.	Mandatory roll out of smart meters with full functionalities to 80% of consumers by 2025 Fully harmonised rules on demand response including rules on penalties and compensation payments.
No new legislative intervention.	This option will give every consumer the right and the means (fit-for-purpose smart meter and dynamic pricing contract) to fully engage in price based DR if (s)he wishes to do so.	This option will allow price and incentive based DR as well as flexibility services to further develop across the EU. Common principles for incentive based DR will also facilitate the opening of balancing markets for cross-border trade.	This guarantees that 80% of consumers across the EU have access to fully functional smart meters by 2025 and hence can fully participate in price based DR and that market barriers for incentive based DR are removed in all Member States.
Roll out of smart meters will remain limited to those Member States that have a positive cost/benefit analysis. In many Member States market barriers for demand response may not be fully removed and DR will not deliver to its potential.	Roll out of smart meters on a per customer basis will not allow reaping in full system-wide benefits, or benefits of economies of scale (reduced roll out costs) Incentive based demand response will not develop across Europe.	As for Option 1, access to smart meters and hence to price based DR will remain limited. Member States will continue to have freedom to design detailed market rules that may hinder the full development of demand response.	It ignores the fact that in 11 Member States the overall costs of a large-scale roll out exceed the benefits and hence that in those Member States a full roll-out is not economically viable under current conditions. Fully harmonised rules on demand response cannot take into account national differences in how e.g. balancing markets are organised and may lead to suboptimal solutions.
Most suitable option(s): Option 2. Only the second option is suited to untap the potential of demand response and hence reduce overall system costs while respecting subsidiarity principles. The third option is likely to deliver the full potential of demand response but may do so at a too high cost at least in those Member States where the roll out of smart meters is not yet economically viable. Options zero and one are not likely to have a relevant impact on the development of demand response and reduction of electricity system cost.			

3.1.2. *Description of the baseline*

For the purpose of this exercise a clear distinction has to be made between technological prerequisites and market arrangements for demand response as those aspects are regulated separately. As such chapter 3.2.1 will focus on the baseline for smart metering and 3.2.2 on dynamic prices and market regulation.

3.1.2.1. Smart Metering

Current Legislation on Smart Metering

Smart metering is a key element in the development of a modern, consumer-centric retail energy system which encompasses active involvement of consumers. In recognition hereof, provisions were included in the Gas Directive and in the Electricity Directive fostering the smart metering roll-out and targeting the active participation of consumers in the energy supply market. These provisions were then complemented with provisions under the Energy Performance in Buildings Directive, and the Energy Efficiency Directive.

The Electricity and Gas Directives[81] require Member States to ensure the implementation of intelligent metering systems that shall assist the active participation of consumers in the energy supply market, and encourage decentralised generation[82], and promote energy efficiency. Article 3 (11) of the Electricity Directive and Article 3(8) of the Gas Directive explicitly state that *"in order to promote energy efficiency, Member States or, where a Member State has so provided, the regulatory authority shall strongly recommend that electricity (or natural gas) undertakings optimise the use of electricity (or gas), for example by providing energy management services, developing innovative pricing formulas, or introducing intelligent metering systems or smart grids, where appropriate."*

This implementation may be conditional, according to Annex I.2 of both the electricity and gas Directive, on a positive economic assessment of the long-term cost and benefits to be completed by 3 September 2012. For electricity, the roll-out can be limited to 80% by 2020 of those positively assessed cases as potentially indicated in a cost-benefit analysis ('CBA'). Furthermore, Member States, or any competent authority they designate, are obliged according to the Electricity and Gas Directive (Annex I.2) to "*ensure the interoperability of those metering systems to be implemented within their territories"* and to "*have due regard to the use of appropriate standards and best practice and the importance of the development of the internal market"* in electricity or natural gas, respectively.

The recast of the Energy Performance of Building Directive ('EPBD'), adopted in May 2010, obliges (Art 8(2)) Member States to "*encourage the introduction of intelligent metering systems whenever a building is constructed or undergoes major renovation,*

[81] Annex I.2 of the Electricity Directive and of the Gas Directive.
[82] Specifically for electricity and linked to smart grid deployment - Electricity Directive, recital (27)

whilst ensuring that this encouragement is in line with point 2 of Annex I to [the Electricity Directive]".

To assist with the preparations for the roll-out, and based on lessons learned and good practices identified through experiences accumulated in Member States, the Commission adopted the Recommendation on preparations for the roll-out of smart metering systems[83]. It aimed at guiding Member States in their choices, drawing particular attention to: (i) key functionalities for fit-for-purpose and pro-consumer arrangements[84]; (ii) data protection and security issues; and (iii), a methodology for a CBA that takes account of all costs and benefits, to the market and the individual consumer, of the roll-out. Following this Recommendation, complementary smart metering provisions were adopted as part of the Energy Efficiency Directive[85].

Smart Metering Deployment in Member States

According to data from the Commission Report *"Benchmarking smart metering deployment in the EU-27"*, as also recently updated[86], to date 19 Member States have committed to rolling out close to 200 million smart meters for electricity by 2020 at a total potential investment of EUR 35 billion.

- 17 Member States - Sweden, Italy, Finland, Malta, Spain, Austria, Poland, UK-GB, Estonia, Romania, Greece, France, Netherlands, Denmark, Luxembourg, Ireland, and lately Latvia – are targeting a nation-wide roll-out to at least 80% of customers by 2020 (with 13 of them going much beyond the target of the Electricity Directive).
- 2 Member States – Germany, Slovakia - are moving to deployment in a selected segment of consumers (to max. 23% by 2020).
- The rest 9 Member States have either decided against at least under current conditions, or have not made a firm commitment yet for a mass-scale or even a selective roll-out.

By 2020, it is projected that almost 72% of European consumers will have a smart meter for electricity[87]. Smart meters for electricity are already being rolled out across the EU. As of 2013, nearly all consumers in Sweden, Finland and Italy, were equipped with smart meters.

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83 *Commission Recommendation on preparations for the roll-out of smart metering systems (2012)* http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32012H0148

84 When it comes to functionalities for electricity smart metering, particularly important for residential consumers are: a readings' update rate of 15 minutes and a standardised interface to transfer and visualise individual consumption data in combination with information on market conditions and service or price options.

85 Energy Efficiency Directive. Art 9(2), 12(2b)

86 *"Status report based on a survey regarding Interoperability, Standards and Functionalities applied in the large scale roll-out of smart metering in EU Member States"* (2015) Smart Grids Task Force Expert Group 1; https://ec.europa.eu/energy/sites/ener/files/documents/EG1_Final%20Report_SM%20Interop%20Standards%20Function.pdf

87 Report from the Commission *"Benchmarking smart metering deployment in the EU-27 with a focus on electricity"* (2014) http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2014%3A356%3AFIN

Despite the progress noted, these implementation plans are falling short of the legislation's intentions. For various legal and technical reasons, the current advancement is rather slow – particularly in view of the fast approaching 2020 target in the case of electricity – and the progress gap to delivery may be further widened by recurring delays in national programmes[88]. In addition, there is a risk that the systems being rolled-out do not bring all the desired benefits to consumers and the market as a whole as they do not include the necessary functionalities to do so. Furthermore, they might not support in all cases standardised interfaces[89] – at home or station level – for the delivery of these functionalities, nor be complemented with additional specifications for improving interoperability on these interfaces and the smooth exchange of information and inter-working between the metering infrastructure and devices or other network platforms in the energy market.

In all cases, the successful roll-out is controlled to a large extent by Member States who are ultimately responsible for the deployment and respective market arrangements[90], and may or may not decide to follow the guidelines tabled by the Commission regarding functionalities and implementation measures for data privacy and security (see Energy Efficiency Directive (Art 9(2b)) and Commission Recommendations "on the preparations for the roll-out of smart metering systems", and "on the data protection impact assessment template for smart grids and smart metering systems" [91]).

3.1.2.2. Market arrangements for demand response

Legislative Background

Mechanisms to remove the barriers to demand flexibility are set out in the Electricity Directive. The Energy Efficiency Directive ('EED') builds on those provisions and elaborates further, promoting its access to and participation in the market and the removal of existing barriers.

The Electricity Directive refers to demand response measures as a means to pursue a wide range of system benefits. The Directive clearly identifies demand response as an alternative to generation to be considered on an equal footing, e.g. when Member States are launching tendering procedures for new capacity in situations where the resource adequacy is insufficient to ensure security of supply (e.g. Art. 8 Electricity Directive). Demand response, alongside energy efficiency, is viewed as one of the measures to combat climate change and ensure security of supply. Demand response is recognised as a means to provide ancillary services to the system in the provisions related to TSO tasks (Art. 12(d) Electricity Directive), and demand side management/energy efficiency

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88 See the Smart Metering Annex of Market Design Evaluation.

89 *"Status report based on a survey regarding Interoperability, Standards and Functionalities applied in the large scale roll-out of smart metering in EU Member States"* (2015) Smart Grids Task Force Expert Group 1.

90 Commission Staff Working Document *"Cost-benefit analyses & state of play of smart metering deployment in the EU-27"* (2014), sections 2.4 and 2.7 http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52014SC0189

91 "*Commission Recommendation on the Data Protection Impact Assessment Template for Smart Grid and Smart Metering Systems"* (2014) http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2014.300.01.0063.01.ENG

measures must be considered as an investment alternative in the context of distribution network development by DSOs planning for new grid capacity (Art. 25(7) Electricity Directive).

Effective price signals are important to encourage efficient use of energy and demand response. In this context, recital 45 of the EED indicates that Member States should ensure that national energy regulatory authorities are able to ensure that network tariffs and regulations support dynamic pricing for demand response measures by final customers. Under Art. 15(1) EED, Member States must ensure that network regulation and tariffs meet criteria listed in Annex XI of the EED, which *inter alia* refer to different possibilities for network and retail tariffs to support dynamic pricing for demand response and incentivise consumers. According to Article 15(4) EED, Member States must ensure the removal of those incentives in transmission and distribution tariffs that might hamper participation of demand response in balancing markets and ancillary services procurement. Most relevant in the context of this impact assessment is however, Article 15(8) EED. In summary, Member States must comply with the following obligations:

- Ensure that national energy regulatory authorities encourage the participation of demand side resources, including demand response, alongside supply in wholesale and retail markets;
- Ensure – subject to technical constraints inherent in managing networks - that TSOs and DSOs treat demand response providers, including demand aggregators in a non-discriminatory way and on the basis of their technical capabilities;
- Promote - subject to technical constraints inherent in managing networks - access to and participation of demand response in balancing, reserve and other system services markets, requiring that the technical or contractual modalities to promote participation of demand response in balancing, reserve and other system services markets - including the participation of aggregators - be defined;
- Ensure the removal of those incentives in transmission and distribution tariffs that might hamper participation of demand response in balancing markets and ancillary services procurement[92].

Situation in Member States with regards to demand response

The EU demand response market is still in its early development phase. This early development has proceeded very differently across Member States that have chosen different approaches to make use of demand side flexibility and to implement demand response. In fact, while Article 15.8 EED formulates principles for the market access of demand service providers and demand side products it has left substantial freedom for Member States to implement these.

While a full transposition check of Art 15.8 EED has not yet been carried out it can already be seen that different national provisions have led to a fragmented European market on demand response with different rules and market opportunities for

[92] See guidance note on Energy Efficiency Directive Art 15 which also covered Industrial Emissions Directive elements http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:52013SC0450

(independent) demand response service providers, different market arrangements between service providers and balancing responsible parties (including compensation payments) and different rules for trading flexibility in the balancing, wholesale and capacity markets.

Explicit (or incentive based) demand response

For explicit demand response, full customer participation in the electricity markets is a prerequisite as addressed in the relevant provisions of the EED. However, because of its complexity only very large industrial consumers can directly engage in the electricity markets while commercial and residential consumers will in most of the cases need to go through demand response service providers (aggregators). These require fair market access for such aggregators and open balancing, wholesale and capacity markets for flexibility products.

a) Market Access for aggregators

The EED stipulates that demand response providers (including aggregators) have to be treated in a non-discriminatory manner. However, market access and market rules for aggregators are regulated differently across Europe. In order to ensure full access to the market at least the following main features have to be addressed in national regulation:

- Clear definition of roles and responsibilities of aggregators within the energy market to ensure legal certainty;
- Clear definition of the relationship between aggregators and Balancing Responsible Parties ('BRPs') that ensures market access of the aggregators at fair conditions. Such rules are essential to ensure that the BRP (which is usually the supplier) has no means of stopping a competitor (e.g. independent aggregator) for engaging with one of its customers and entering the market.

In many Member States such a framework for aggregators is effectively missing or independent aggregation is legally banned. This applies for Bulgaria, Croatia, Cyprus, Czech Republic, Estonia, Greece Italy, Malta, Portugal, Spain and Slovakia. But also in Member States where legislation for aggregators and demand response has been established many differences can be noted.

To date, France is the only Member State that developed a complete framework for demand response explicitly enabling independent aggregation by guaranteeing contractual freedom between the consumer and the aggregator without supplier's consent. A standardised framework also exists for the compensation mechanisms, however, it is claimed by some stakeholders that this mechanism greatly penalises the aggregator, overcompensates the BRP and hence renders the business case for independent aggregators negative.

Other Member States allow (independent) aggregation but to varying degrees. Independent aggregators are allowed in Belgium, Ireland, UK, Germany and Austria albeit not all markets are effectively opened to them as rules, e.g. in Austria, effectively limit their activity to aggregate loads of big consumers. In some Member States like Poland, the Netherlands and in the Nordic markets aggregators have also to become suppliers or offer their services jointly with suppliers but cannot act as completely independent service providers. In all Member States, apart from France, the UK and Ireland, the explicit consent of the consumer's supplier is required for aggregators to enter into the market. Equally in those Member States, a clear framework for compensation payments is missing and therefore such payments may need to be individually negotiated between the independent aggregator and supplier as a precondition for accessing the consumer. As such, the incumbent supplier can effectively block market access at least for independent aggregators.

b) Access of flexibility to the markets

The EED requires Member States to promote access to and participation of demand response in balancing, reserve and other system services markets *inter alia* by engaging the national authorities (or where relevant, the TSOs and DSOs) to define technical modalities on the basis of the technical requirements of these markets and the capabilities of demand response; these specifications must include the participation of aggregators.

Technical modalities or requirements can be for example the minimum size of a load, the activation time or the duration for which a product needs to be provided. Traditionally, requirements have been designed along the capacities of big generation units, e.g. coal power plants. Demand side products naturally face problems to meet these requirements, even if aggregated. Another aspect is that prequalification requirements often have to be fulfilled per unit and not at the aggregated level. As the following stock-taking will show, access of demand resources to the wholesale, balancing and recently capacity markets varies considerably across Member States.

The analysis of the *status quo* suggests that in most of the Member States access to the markets is either up-front restricted or preconditions make it difficult for demand side products to qualify and compete. In roughly only a third of the Member States demand side products have fair access to the markets and in even fewer Member States demand response is actually happening. Generally, the balancing markets tend to be more open to demand side products than the wholesale markets.

In many Member States demand side resources do not play any role in the markets. Examples for this situation would be Cyprus, Malta and Croatia. But also in many other Member States markets are practically closed and allow for only very restricted participation of the demand side. Often it is only suppliers or big industrial actors that are allowed to bid in the markets. In those cases, there are usually very specific demand flexibility programmes for selected, mainly very large, actors. For example, in Italy, Spain and Greece interruptibility programmes have been or are being introduced for large industrial loads.

Other countries are one step ahead and have partly opened their markets, while practical barriers still hamper the market access. The balancing market in Germany for example is in principle open to demand loads, but heavy prequalification (e.g. extensive testing) and programme requirements (e.g. bid size) block any major remand response-activity. Similarly, practical barriers, in particular for aggregated demand, hamper access to the – theoretically open – balancing markets in Slovenia and Denmark and to some degree also in Sweden.

There is a group of countries where demand response has already assumed a more important role. Belgium for example adapted their technical requirements and offers quite a large range of possibilities for demand side resources to participate in the balancing and ancillary services markets. In the UK, the market for ancillary services[93] is open to demand response and a dedicated 'Demand Side Balancing Reserve' mechanism was established in 2015. Meanwhile, France has become probably the Member State with the broadest general access of demand response to both the balancing and the wholesale market. A general framework is in place that facilitates demand side participation, which has caused demand response providers to begin expanding onto this market.

The table below summarizes in which Member States markets are open to demand response and the amount of incentive based demand response currently estimated in those Member States. While demand response is allowed to participate in most Member States, activated volumes of more than 100 GW can only be found in 13 Member States.

Table 1: Uptake of incentive-based demand response

Member State	Demand Side Products (DSP) in energy markets	DSP in balancing markets	DSP in capacity mechanisms	Estimated demand response for 2016 (in GW)
Austria	Yes	Yes		104
Belgium	Yes	Yes	Yes	689
Bulgaria	No	No		0
Croatia	No	No		0
Cyprus	No market	No market		0
Czech Republic	Yes	Yes		49
Denmark	Yes	Yes		566
Estonia	Yes	No		0
Finland	Yes	Yes	Yes	810
France	Yes	Yes	Yes	1689
Germany	Yes	Yes	Yes	860
Greece	No (2015)	No		1527
Hungary	Yes	Yes		30
Ireland	Yes	Yes	Yes	48
Italy	Yes	No	Yes	4131
Latvia	Yes	No	Yes	7
Lithuania	unclear	No		0
Luxembourg	No information	No information		
Malta	No market	No market		
Netherlands	Yes	Yes		170
Poland	Yes	Yes	No	228
Portugal	Yes	No		40
Romania	Yes	Yes		79
Slovakia	Yes	Yes		40
Slovenia	No	Yes		21
Spain	Yes	No	Yes	2083
Sweden	Yes	Yes	Yes	666
UK	Yes	Yes	Yes	1792
Total				15628

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering"(2016) COWI

Implicit (price based) demand response

93 The range of functions which TSOs contract so that they can guarantee system security, including black start capability, frequency response, fast reserve and the provision of reactive power.

For implicit demand response, smart metering systems as well as the availability of dynamic pricing contracts linked to the wholesale market are prerequisites. For smart metering systems roll-out plans exist for 17 Member States, while in 2 Member States a partial roll-out is planned and in a number of those Member States the functionalities of the smart metering systems (enabling communication interfaces, frequent update intervals, advanced tariffication, etc.) may not allow for automatically reacting to price signals (a complete analysis is provided within the evaluation fiche on smart metering). EU legislation does not currently impose any requirements on Member States to activate price based (or implicit) demand response.

In order to activate price based demand response the availability of dynamic electricity pricing contracts are a prerequisite as those contracts can incentivise consumers to adjust their consumption according to the real time price signal. The ACER/CEER Market Monitoring Report contains a dedicated analysis of the competition situation in all Member States in the retail market and the different offers available to the customers. This analysis shows that only in Denmark, Sweden and Finland dynamic pricing contracts that are linked to the spot market are available to residential consumers while only in Sweden and Norway such contracts represent more than 10% of all consumer contracts. In terms of costs for the consumers the ACER/CEER analysis shows that offers linked to the spot market are slightly cheaper for the consumer than fixed or variable offers in the same country.

Graph 1: Type of energy pricing of electricity offers in EU Member States capital cities,

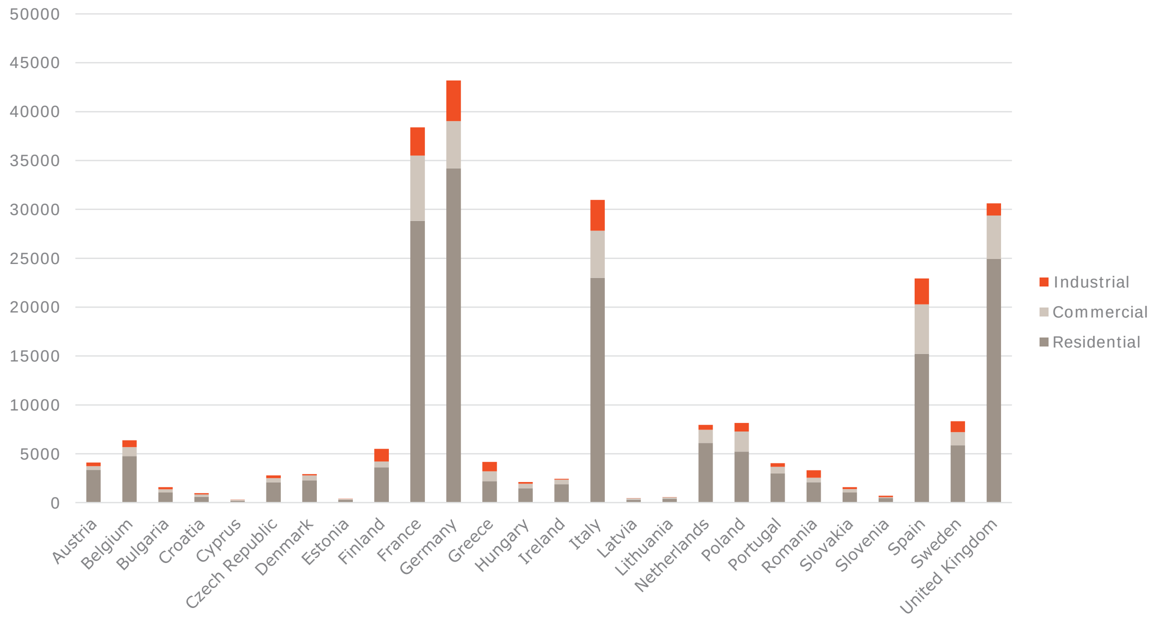
Source: "Market Monitoring Report 2014" (2015) ACER

In addition to the three Member States addressed above also in Estonia, Spain, Austria, Belgium, Netherlands and Germany dynamic pricing contracts are available on the market – at least for certain consumer groups - which were not yet included in the ACER/CEER analysis. However, the uptake of such tariffs is currently very low and no detailed data is available yet.

As a high level estimate for the EU, studies and data support current load shifting due to times of use tariffs and price based demand response ranging from negligible (most Member States), to around 1% (most Northern European Countries) to 6-7% (Finland and France). The overall load that is shifted due to Time-of-Use ('ToU') and dynamic tariffs to date would be of the order of 5.7GW (or 1.2% of peak load in Member States where dynamic tariffs are offered).

While data on current demand response levels is difficult to obtain, estimates from the impact assessment study[94] indicate the use of approx. 21.4 GW of demand response per year in Europe including the 5.7GW from ToU and dynamic tariffs referred to above. This is only a small fraction of the demand response potential that adds up to approx. 120.000 MW in 2020 and 160.000 MW in 2030 which will lay mainly with residential consumers. However, this potential is purely theoretical (not taking into account commercial viability and technology restriction) and for 2030 greatly depends on the uptake of flexible loads such as electric vehicles and heat pumps in the residential sector.

Graph 2: Theoretical demand response potential 2030



Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

3.1.3. *Deficiencies of current legislation*

A detailed analysis of the existing legislation on smart metering systems and demand response in European and national legislation has been carried out in the framework of the evaluation. The detailed results of this analysis are reported in the annexes to the Market Design Initiative evaluation (annexes on "Details on the EU framework for smart metering roll-out and use of smart meters" and "Details on the EU framework for Demand Side Flexibility")

[94] *"Impact Assessment support Study on downstream flexibility, demand response and smart metering"*, (2016) COWI

3.1.3.1. Deficiencies of current Smart Metering Legislation

Looking at the current situation with smart metering deployment in the Member States, despite the progress noted, EU-wide implementation is falling short of the legislator's intentions, in terms of level of commitment, roll-out speed, and purpose. In the light of the developments so far, the existing provisions can be assessed as follows.

In terms of **effectiveness**, the evidence available generally suggests that the smart metering provisions currently in place have been less effective than intended. This is partly a result of the 'soft'/unspecific nature of some obligations they lay (i.e. Article 8(2) of the EPBD. Enforcing the recommended[95] minimum functionalities for smart metering systems on an EU level, and consistently promoting the use of available standards to ensure connectivity and '*interoperability*', as well as best practices, while having due regard to data security and privacy, would guarantee a coherent, future-proof system able to support novel energy services and deliver benefits to consumers, in line with the legislator's intentions.

There is not enough evidence at the moment to evaluate the **efficiency** of the intervention in terms of proportionality between impacts and resources/means deployed. This is due to the fact that most of the large-scale roll-out campaigns have yet to start unfolding making the field data available rather scarce; there are only projections available based on Member States cost-benefit assessments.

In terms of **relevance**, the evaluated smart metering provisions, considering current needs and problems, remain highly valid. This said, they could though be further enhanced, by elaborating them as to: (i) spell out how the term of *'active participation'* is to be understood, and expected to be realised in practical terms, namely define requirements for functionality, connectivity, interoperability, and standards to use; (ii) include an obligation to Member States to officially set the minimum technical and functional requirements for the smart metering systems to be deployed, the market arrangements, and clarify the roles/responsibilities of those involved in the roll-out.

In terms of **coherence** – internally and with other EU actions – even though no clear contradictions could be pointed out, the evaluation has identified some room for improvement. Linking of the term *'actual time of use'* in Article 9(2a) and Article 9(1) EED to smart metering provisions erroneously restricts the functional requirements of the targeted set-ups and raises questions about coherence with the framework for promoting smart meters. There is therefore a need to clarify that a wide range of functionalities is in fact promoted, as those recommended by the Commission, that go much beyond the capability of just *'actual time of use'* information which usually refers to advanced, and not smart metering.

Finally, evidence points to the need to eliminate ambiguities and to further elaborate, clarify, and even strengthen the existing provisions, in order to give certainty to those planning to invest and ensure that smart metering roll-outs move in the right direction, and regain **EU added-value**. This is to be done by: (i) safeguarding common functionality, and share of best practices; (ii) ensuring coherence, interoperability,

95 *Commission Recommendation on preparations for the roll-out of smart metering systems (2012)* http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32012H0148

synergies, and economies of scale, boosting competitiveness of European industry (both in manufacturing and in energy services and product provision); and (iii), ultimately delivering the right conditions for the internal market benefits to reach also consumers across the EU.

3.1.3.2. Deficiencies of current regulation on demand response

It was the objective of the existing European legislation to put demand response on equal footing with generation and to ensure that demand response providers, including aggregators, are treated in a non-discriminatory way. While provisions aiming at realising those objectives have been put in place in many Member States, the development of demand response across Member States varies significantly and has led to fragmented markets. Especially the different treatment of independent aggregators across the EU is a matter of concern. It can therefore be concluded that additional provisions further specifying the existing provisions are needed to ensure a harmonised development and enable price and incentive based demand response across Europe.

In terms of **effectiveness**, the evidence available generally suggests that the demand response provisions currently in place have been less effective than intended. The provisions have not been effective in removing the primary market barriers especially for independent demand response service-providers and creating a level playing field for them. Instead the heterogeneous development of demand response has led to fragmented markets across the EU. This is mainly due to the high degree of freedom the existing provisions leave to Member States. The different treatment especially of independent demand response service-providers in national energy markets as well as of flexibility products in electricity markets risk undermining the large-scale deployment of demand response needed as well as the functioning of the internal energy market.

There is not enough evidence at the moment to evaluate the **efficiency** of the intervention in terms of proportionality between impacts and resources/means deployed.

In terms of **relevance**, the herein evaluated demand response provisions remain highly valid. Full exploitation of demand response remains crucial to manage the energy transition as it is an enabler for efficiently integrating variable renewables into the energy system. However, as pointed out above, the existing provisions have not been effective in deploying demand response sufficiently quickly across Europe.

In terms of **coherence** the evaluation has shown that the provisions on demand response are fully coherent with other legislative provisions within the Electricity Directive, the EED, the RED and the EPBD.

Finally, considering the **EU added value**, it remains crucial to ensure that harmonised demand response provisions are in place across the EU to guarantee a functioning internal energy market. Even more because under the upgrading of the wholesale market within the market design initiative the Commission will also look into opening national balancing markets where flexibility may then be traded across borders. Full availability of demand response in all Member States will then be crucial for the functioning of those cross-border balancing markets.

3.1.4. *Presentation of the options*

Option 0: BAU

As outlined in chapter 3 the existing provisions on smart meters and demand response have not proven to be fully effective in reaching the goals of rolling out fully functional smart metering systems to at least 80% of consumers EU-wide by 2020 and to put demand response on equal footing with generation.

Option 0+: Non-regulatory approach

Considering non-legislative intervention and just resorting to Option 0+ of a potential stronger enforcement and/or voluntary cooperation, would not allow for an improvement of the current situation regarding the uptake of fit-for-purpose smart metering and of the market conditions for demand response to flourish. Option 0+ is not expected to remove market barriers for demand side flexibility to reach its full potential, and therefore will not deliver the policy objectives.

According to the Commission's assessment, the provisions related to smart metering systems have been correctly transposed in Member States and hence, as argued earlier, no further enforcement leading to a greater roll out of such systems is realistic. The provisions of Art 15(8) EED related to demand response have not yet been subject to a full transposition check or any infringements. However, even in those Member States where the provisions have been fully and correctly transposed market barriers for independent service providers continue to exist. This suggests that the current provisions are not sufficiently explicit to fully remove all remaining barriers to demand response. As such a stronger enforcement of existing provisions may in some Member States lead to a greater take up of demand response but this alone will not be sufficient to provide a full level playing field as intended by European legislation, and would not deliver the policy objectives, which is the reason this option was not further considered.

Option 1: Enable price based demand response

Smart metering systems are the key prerequisite for properly accounting for, and then rewarding, consumers' involvement in demand response or the use of distributed energy resources. However, it is expected that a smart meter roll-out will be realised in only 17 Member States (plus a partial roll-out in 2 Member States). In some of those Member States the roll-out may take place without all the functionalities identified in the Commission Recommendation on the preparations for the roll-out of smart metering systems.

Our objective is to ensure that interoperable smart metering systems with the right functionalities are available to all consumers. The policy measures to ensure that price based demand response can develop include:

- Give consumers the right to request a meter with the full 10 functionalities when roll-out without full functionality is taking place or has already been completed.

- Give consumers the right to request a smart meter with full functionalities when wide scale roll-out is not carried out[96].
- Grant consumers the right to an electricity pricing contract linked to the development of the spot market.

Option 2: Enable price and incentive based demand response across Europe

In addition to enabling price based demand response schemes as in Option 1, the objective in this area is to remove the key barriers to incentive based demand response and flexibility services in order to facilitate the market-driven deployment of these technologies to the greatest practicable and economically viable extent. The new rules ensuring full market access for independent aggregators will address the following:

- Ensuring full non-discriminatory market access for consumers to all relevant markets either individually or through third part aggregators.
- Ensuring that each market participant contributes to the system costs according to the costs and benefits (s)he induces to the system.
- Removal of barriers at wholesale, balancing at capacity markets for aggregated loads and for flexibility.

Option 3: Mandatory smart meter roll-out and full EU framework for incentive-based demand response across Europe

The third option goes beyond the provision in Option 2. Instead of the right for consumers to request a smart meter, it contains an obligation for a mandatory roll-out of smart meters with the 10 recommended functionalities by 2025, for 80% of consumers in every Member State. In addition, it contains a detailed framework for demand response that no longer only defines principles for this framework but also defines favourable financial rules for aggregators: The financial arrangements between aggregators and BRPs explicitly exclude any financial transfers between aggregators and BRPs. The provisions on access of aggregated loads to wholesale, balancing and capacity markets remain unchanged from Option 2.

[96] In both cases the requested systems must be able to ensure interoperability among the operators responsible for metering and other participants in the electricity market and thus support the provision of energy management and information services of benefit to the consumer.

3.1.5. *Comparison of the options*

a. Effectiveness of options

In the context of this impact assessment two objectives are envisaged:

- The accelerated deployment of fit-for-purpose smart metering systems that will enable consumers to receive timely and accurate information on which they can promptly act and accordingly adjust their consumption – in volume and time –and benefit from new energy services (e.g. demand response)

- The uptake of demand response for consumer and system benefit

Smart Metering uptake

Assuming that no new EU intervention takes place, apart from the stronger enforcement of existing legislation which is foreseen under **option 0**, and deployment plans go ahead as they currently stand, smart meters will be installed only in those Member States where their deployment is currently positively assessed, leading to a maximum EU penetration rate of close to 72% by 2020. However, the systems to be rolled out will not necessarily be interoperable, nor equipped in all cases, as recent data have shown[97,98], with those consumer benefitting functionalities (as listed in "Commission Recommendation on preparations for the roll-out of smart metering systems") that support his participation in novel energy services' programmes.

It is important to note here that increased functionality is directly associated to benefits, but not to costs; it does not push up the overall cost of the deployment, given that it is mainly software driven and its incremental cost is relatively low[99]. Issues related to economies of scale and customisation may be more important in driving overall costs. So, selecting fewer items from the set of common minimum functionalities does not necessarily translate into less expensive systems. This makes a compelling case for adhering from the start of the roll-out to the full set of the recommended functionalities[100] for the smart metering systems rolled-out.

Bearing in mind the intentions of the Member States regarding smart metering functionalities, and for rolling out standardised interfaces to support the communication of the metering infrastructure with devices and business platforms, in practice, much

97 Commission Staff Working Document *"Cost-benefit analyses & state of play of smart metering deployment in the EU-27"* (2014) Table 8

98 *"Status report based on a survey regarding Interoperability, Standards and Functionalities applied in the large scale roll-out of smart metering in EU Member States"* (2015) Smart Grids Task Force Expert Group 1

99 *"Cost benefit analysis of smart metering systems in EU Member States"* (2015) ICCS-NTUA & AD Mercados EMI ; *"Impact Assessment support study on downstream flexibility, demand response and smart metering"* (2016) COWI

100 Report from the Commission *"Benchmarking smart metering deployment in the EU-27 with a focus on electricity"* (2014) http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2014%3A356%3AFIN; supported with data from the Commission Staff Working Document "*Cost-benefit analyses & state of play of smart metering deployment in the EU-27"* (2014) .

more than 30% of EU customers by 2020 will be effectively denied the means – a fully functional smart metering system - for getting involved in demand response schemes. Furthermore, given that the meters installed will be in place for the next 15 years, which is their average economic lifetime, the overall demand response potential will be significantly reduced up to 2030.

For estimating the smart metering deployment for the alternative **Option 1** (smart meter or its functional upgrade on request by the consumer) the following assumptions are made:

- In countries with a reported large-scale roll-out of smart metering systems, the roll-out occurs as planned, with the recommended functionalities not being though throughout implemented. In all cases, customers will have access to dynamic tariffs by 2020. This reflects greater customer and supplier awareness of the benefits of smart meters;
- In countries with either a limited (in terms of customer coverage or functionality) roll-out or no planned roll-out, fully functional smart meters (or their upgrade) will be made available to customers on demand.

The extent to which customers will choose the installation of a smart meter (or its functional upgrade) will depend on a range of factors, including the proportion of overall benefits that it could capture for them. Where a customer is faced with the full cost of smart metering installation, extremely low take up is envisaged in the relevant Member States based on current technology and its cost.

The analysis of national cost-benefit analyses for the roll-out of smart meters in those countries not proceeding with a large scale roll-out has shown that customer related benefits from smart metering systems are generally significantly lower than corresponding per metering point costs. In two cases (Germany and Slovakia) the national CBAs have concluded that a mandatory roll-out to all consumers would not be beneficial but only for consumers above a certain consumption threshold:

- In Germany a mandatory roll-out for all consumers with an annual consumption above 6000kWh is proposed;
- In Slovakia, the CBA considers that consumers with annual consumption above 4000kWh (covering 23% of metering points and 53% of Low Voltage consumption) will overall benefit from an installation.

For the purpose of analysis, it is assumed that for all countries without a full purpose (in terms of scale - nationwide, and function) roll-out of smart meters, the uptake of a smart meter paid for by the consumer will be low in the short to medium term (up to 2020), but may well increase significantly in the subsequent period to 2030 as the costs of meters, communications and information technology fall, and the spread of appliances conducive to price-based demand response rises. Therefore, the following estimates are made:

- Take up of smart meters of around 10% of residential and small commercial consumers by 2020 in Member States where no full purpose roll-out is planned;
- Take up of smart meters of 40% of residential and small commercial consumers by 2030 in Member States where no full purpose roll-out is planned.

While no additional smart metering related measures are foreseen under **Option 2**, under **Option 3** a mandatory roll-out of smart meters to at least 80% of consumers in all Member States is included, and this is to materialise irrespectively of the result of their national assessments for the cost-effectiveness and feasibility of this deployment. Such a mandatory roll-out will eventually lead to approximately 90% of all consumers having a fully functional smart metering system installed by 2030. This reflects current experience with smart metering roll-out where some installations for technical reasons may be too expensive and some consumers refusing to have a smart meter installed because of privacy concerns.

In the light of these assumptions, the resulting estimates of smart meter roll-out and access to dynamic tariffs under Option 1, 2 and 3 are set out below.

Table 2: Overview smart meter uptake

	BAU = Option 0	Option 1	Option 2	Option 3
2016				
Smart meter	35%	35%	35%	35%
2020				
Smart meter	71%	72%	72%	72%
2030				
Smart meter	74%	81%	81%	90%

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

Uptake of dynamic price contracts

In order to participate in price based demand response schemes, consumers not only have to have a smart meter but also a dynamic electricity price contract. Under all options, it is considered that the consumer must voluntarily opt in for such a contract. At this stage, only estimates can be made on the number of consumer with a smart meter opting for dynamic contracts, time of use contracts and static contracts. The following estimates have been used for this analysis on the basis of various studies as well as pilot projects and initial experience in the Nordic countries[101]:

[101] The core estimated figures are in line with international trial studies and practical evidence, including:
- The consumer survey of "*Smart Energy GB survey*", which states that around 30% of the people were either strongly or moderately in favour of switching to a ToU tariff;
- The take-up rate of the Critical Peak Pricing ("CPP") tempo tariff in France that was slightly less than 20% of the total consumers.

Table 3: Uptake of dynamic and ToU price contracts of consumers with smart meters

	BAU	Option 1	Option 2	Option 3
2016 ToU Dynamic	 10% 0%	 10% 0%	 10% 0%	 10% 0%
2020 ToU Dynamic	 18% 3%	 18% 3%	 18% 3%	 18% 3%
2030 ToU Dynamic	 26% 16%	 26% 16%	 26% 16%	 26% 16%

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

The average uptake rate is identical for all options as for all options it is assumed that dynamic tariffs are available for those consumers who wish to have one. In the case of Member States not currently planning a large scale roll-out of smart metering systems and for which optional take up applies under Option 1, a higher take up rate is assumed for the calculation. This is done under the assumption that consumers actively opting for smart meters are equally more likely to actively opt in for advanced price contracts. Hence the take up rate for static ToU and Critical Peak Pricing (CPP) doubled in 2020 and 2030 for customers with a smart meter (52% and 32% respectively in 2030).

Demand response uptake

The uptake of demand response was calculated on the basis of the smart meter roll-out and uptake of dynamic price contracts as presented above taking into account the overall demand response potential as presented in chapter 3.1.2.

Option 0 (BAU)

In case no additional measures are taken demand response will still develop across Europe. The roll-out of smart meters will be carried out as planned and dynamic price contracts will be available to consumers in Member States where mart meters are rolled out and where the retail market is sufficiently competitive. Under the BAU, an increase of price based demand response from 5.8 GW to 15.4 GW in 2030 is accepted.

It is important to note that the uptake of demand response depends heavily on the appliances/loads residential consumers have in their possession:

- For normal appliances, 4.9% of potential demand response is captured, while
- For electric vehicles, heat pumps and smart appliances, 18.6% of potential demand response is captured.

These figures are very sensitive to the take-up of new forms of price contracts. The proportion of potential demand response for electric vehicles and heat pumps captured ranges from around 13% for Member States not currently supporting a widespread roll-out of smart metering systems to around 21% if it is planning a full scale roll-out.

Incentive-based demand response will only develop very slowly as in the absence of a clear enabling framework independent aggregation will remain limited and access of flexibility to the markets limited. In total, under the BAU option demand response can increase from 21.4 GW in 2016 to 34.4 GW in 2030 or by 60%.

Option 1

In case only price based demand response is further enabled, the calculation shows that total demand response would only increase compared to the BAU by approx. 2.5 GW by 2030 at an EU-wide level. This reflects the moderate additional uptake of smart meters when each consumer has the right to have it installed.

Option 2

Incentive-based demand response is already represented in the wholesale energy markets in half of the Member States. In policy Option 2, it is assumed that all Member States having introduced some incentive based demand response already will reach a level of 5 per cent peak reduction in 2030, gradually increasing from today's level. The increased level of demand response compared to Option 1 is due to adjustments in programme requirements to better reflect the needs of demand side. This includes allowing aggregated bids in the markets allowing aggregators enter the market as a service provider for industry and large commercial consumers. There is also a standard process for settlements between aggregators and suppliers to facilitate aggregation. Also, all Member States will introduce incentive based demand response and the Member States not currently having incentive based demand response, will reach a level of 3 per cent of peak load in 2030, the potential gradually being introduced from 2021. The reasoning for take-up of demand response in these Member States is the same, but they will start from a lower level than Member States where demand response is already taking place.

Those measures will lead to an increase of incentive based demand response by approx. 15.6 GW or more than 80% compared to the BAU scenario. Under option 2 price based demand response stays stable as no additional measures are introduced. Hence, total demand response compared to the BAU scenario will increase by approx. 18GW or 52%[102].

Option 3

In policy Option 3 it is assumed that all Member States having already introduced some incentive based demand response will reach a level of 8 per cent peak reduction in 2030, gradually increasing from today's level. Also, all Member States will introduce incentive-based demand response and the Member States not currently having incentive based demand response, will reach a level of 5 per cent of peak load in 2030, the potential gradually being introduced from 2021. The increased level of demand response compared to Option 2 is due to aggregators entering the market as a service provider under more favourable conditions. Also, the prices for balancing reserves have increased due to increased imbalances in the energy market. Those measures will lead to an increase of incentive based demand response by approx. 20 GW or approximately double compared to the BAU scenario.

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102 In this Impact Assessment only the impact demand response is being quantified. Other forms of consumer flexibility such as self-generation are being assessed under the RED II Impact assessment.

Under this option it is assumed that price based demand response will remain unchanged. While more consumers will have access to a smart meter it is unlikely that those additional consumers who have not opted for a smart meter in the first place will request a dynamic tariff and hence they will not participate in demand response schemes. Total demand response compared to the BAU scenario will therefore increase by approx. 23GW or 66% or by 4.7GW compared to Option 2.

Table 4: Overview of demand response (in GW/year) uptake for different options

	BAU	Option 1	Option 2	Option 3
2016				
Price-based	5.8	5.8	5.8	5.8
Incentive-based	15.6	15.6	15.6	15.6
Total	**21.4**	**21.4**	**21.4**	**21.4**
2020				
Price-based	6.4	6.9	6.9	6.9
Incentive-based	16.3	16.3	20.3	21.4
Total	**22.7**	**23.3**	**27.2**	**28.4**
2030				
Price-based	15.4	17.9	17.9	17.9
Incentive-based	19.0	19.0	34.6	39.3
Total	**34.4**	**36.8**	**52.4**	**57.1**

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

b. Key economic impacts

Cost and benefits of smart metering

In this Section the cost-effectiveness and impact of smart metering is to be seen as part of the bigger picture of delivering services to the consumer and enabling his participation in price based demand response, and allowing him to offer his flexibility to the energy system, and be rewarded for it.

Under **option 0**, the smart metering roll-out, following in most cases a positive CBA undertaken by the Member States, is assumed to take place as planned. A complete listing of *costs* and *benefits* associated with smart metering deployment in Member States can be found in the Commission Benchmarking Report issued in 2014[103]. Available data there coming from the CBAs[104] of Member States that are proceeding with the roll-out,

103 (see Table 25 in) Report from the Commission *"Benchmarking smart metering deployment in the EU-27 with a focus on electricity"* (2014) http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2014%3A356%3AFIN; and accompanying (i) Commission Staff Working Document *"Cost-benefit analyses & state of play of smart metering deployment in the EU-27"* (2014), (ii) Commission Staff Working Document *"Country fiches for electricity smart metering"* (2014)

104 idem

indicate, despite their divergence, that the cost of installing a smart metering system for electricity is on average close to EUR 225 per customer, while the benefit (per customer) is EUR 309 accompanied by energy savings in the order of 3% and up to 9.9% of peak load shifting.

The peak load shifting expectations vary greatly across the Member States; namely from 0.75% (UK) and 1% (Poland) to 9.9% in Ireland in the cluster of Member States that are preparing a roll-out, and from 1.2% (Czech Republic) to 4.5% quoted in Lithuania in the batch of Member States that are not presently proceeding with large-scale deployment. These significant differences may be due to: (i) different experiences coming from locally run pilot projects and/or hypotheses adopted in building the scenarios;[105], and (ii), different patterns considered in electricity consumption, e.g. presence of district heating, wide-spread use of gas, etc.

On the *cost side*, meter costs (CAPEX and OPEX) are identified by the majority of Member States as dominant followed by the capital and operational cost due to data communication. In most countries (and relative to the electricity deployment arrangement of the country), the smart metering investment and installation cost appears as an upfront cost for the distribution system operator in the initial stage of the deployment; however, in most cases they are later fully or partly passed to the final consumer through network tariffs.

Regarding *benefits*, data show that in a number of Member States – the Czech Republic, Denmark, Estonia, France, Italy, Luxembourg and Romania – the distribution system operator is the first/large direct *beneficiary* of the electricity smart metering, followed by the consumer, and the energy supplier. The associated benefits have little to do with demand response, and are related to administrative improvements in the areas of meter reading, dis/re-connection, identification of system problems, fraud detection, as well as increased customer services. Finally, other benefits can also be linked to smart metering such as CO_2 emissions reduction due to first energy savings, as well as more efficient electricity network operation (reduced technical and commercial losses); these result in benefits accrued to the whole society.

It is important to note that to obtain full benefits, particularly consumption-related ones, greater meter functionality is required. Yet, the CBAs show no direct link between cost and functionality[106]. So, asking Member States to give under **Option 1** and **Option 2** the entitlement to consumers to request a smart meter with full functionality, or the upgrade of an existing one, should not pose any disproportionate costs on top of the meter unit cost. However, the fact that smart meters will end up being rolled out on customer-per customer basis will not allow reaping in full system-wide benefits or benefits of scale and will lead to higher per unit cost/benefit ratios.

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105 e.g. consumers' participation rate in demand response programmes (time-of-use pricing, etc.), different consumer engagement strategies (e.g. indirect vs. direct feedback)

106 Report from the Commission *"Benchmarking smart metering deployment in the EU-27 with a focus on electricity"* (2014); also confirmed in (i) *"Cost benefit analysis of smart metering systems in EU Member States"* (2015) ICCS-NTUA & AD Mercados EMI; and (ii) *"Steering the implementation of smart metering solutions throughout Europe: Final Report"* (2014) FP7 project Meter-ON, p.9 and p.11; http://www.meter-on.eu/file/2014/10/Meter-ON%20Final%20report-%20Oct%202014.pdf

In those countries where a large-scale roll-out is currently not foreseen and additional meters are to be installed on customers' request, under **Option 1** and **Option 2**, the total investment for installing additional meters could – as a first approximation - reach EUR 5 billion by 2030[107] for a penetration rate of 81% (compared to 74% in BAU). Half of these costs for the installation of additional meters could potentially be offset by benefits (for example lower costs/avoided costs of meter reading and operation, reduced commercial losses[108]) other than those related to demand response[109]. As a result, the total cost by 2030 for the installation of these additional meters requested by consumers within the EU – under Option 1 and Option 2 – could go down to EUR 2.47 billion; this corresponds to an annual cost of EUR 215 million, for a period of 15 years (which is the average economic lifetime of smart meters) considering a discount rate of 3.5%.

A similar calculation could also be undertaken for **Option 3** which will enforce the roll-out of smart metering in all cases including those where deployment was found to be non-beneficial according to the national economic assessment of long-term costs and benefits. In this case, a mandatory roll-out throughout the EU could result in achieving ultimately a penetration rate of 90% by 2030, and the additional smart metering installation costs could rise beyond EUR 14 billion[110]. This figure represents the additional cost should a mandatory smart meter roll-out is obligated throughout the EU. Half of these costs, as argued earlier, could potentially be balanced by benefits linked to lower costs for meter reading and operation and avoided commercial losses[111]. Consequently, the total additional investment is halved, and the corresponding 'net' annual cost (for 15 years modelling period, at 3.5% rate) is estimated at EUR 613 million (per year).

The tables below present the specific costs of additional meters installation, on consumer request or obligated by legislation (Option 3), calculated per Member State, for the alternative options considered.

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107 The calculation is based on the projected smart metering penetration rate by 2030, and on an average cost per metering point of EUR 279. This value is worked out from data of Member States' CBAs – both positive and negative in their outcome - that were analysed under the "*Study on cost benefit analysis of Smart Metering Systems in EU Member States-Final Report"* (2015) AF Mercados EMI and NTUA, and presented on Table 8, p. 26 of the aforementioned report. This average value of EUR 279 per metering point includes the smart meter costs, the information technology cost, communications costs and costs for the installation of an In-Home Display (in the case of two Member States cost-benefit analyses).
Note – The accuracy of this calculation depends on the extent that a fixed cost (which is the total cost for rolling-out to 80% of population) can be proportionately shared, and accordingly deployed to derive the 'unit cost', which is then used to estimate, for any penetration rate, the cost of installation of smart metering.

108 see Figure 4, page 34 of the "*Study on cost benefit analysis of Smart Metering Systems in EU Member States-Final Report"* (2015) AF Mercados EMI and NTUA.

109 *"Impact Assessment support Study on downstream flexibility, demand response and smart metering"* (2016) COWI.

110 *Idem*

111 *idem*

Table 5: Overview of estimated costs for additional smart meter installation by 2030, considering options 1 and 2

		BAU=Option 0	Option 1, Option 2	
Country	**Metering points**	**Smart meter penetration rate by 2030**	**Additional meters by 2030 (compared to BAU)**	**Indicative cost (EUR million) by 2030**
Austria	5,700,000	95%	-	-
Belgium	5,975,000	0%	40%	667
Bulgaria	4,000,000	0%	40%	446
Croatia	2,500,000	0%	40%	279
Cyprus	450,000	0%	40%	50
Czech Republic	5,700,000	0%	40%	636
Denmark	3,280,000	100%	-	-
Estonia	709,000	100%	-	-
Finland	3,300,000	100%	-	-
France	35,000,000	95%	-	-
Germany	47,900,000	31%	10%	1,270
Greece	7,000,000	80%	-	-
Hungary	4,063,366	0%	40%	453
Ireland	2,200,000	100%	-	-
Italy	36,700,000	99%	-	-
Latvia	1,089,109	95%	-	-
Lithuania	1,600,000	0%	40%	179
Luxembourg	260,000	95%	-	-
Malta	260,000	100%	-	-
Netherlands	7,600,000	100%	-	-
Poland	16,500,000	100%	-	-
Portugal	6,500,000	0%	40%	725
Romania	9,000,000	100%	-	-
Slovakia	2,625,000	23%	17%	125
Slovenia	1,000,000	0%	40%	112
Spain	27,768,258	100%	-	-
Sweden	5,200,000	100%	-	-
UK	32,940,000	100%	-	-
TOTAL	**276,819,733**	**74%**	**7%**	**4,942**

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

Table 6: Overview of estimated costs for additional smart meter installation by 2030 considering Option 3

		BAU=Option 0	Option 3	
Country	**Metering points**	**Smart meter penetration rate by 2030**	**Additional meters by 2030 (compared to BAU)**	**Indicative cost (EUR million) by 2030**
Austria	5,700,000	95%	-	-
Belgium	5,975,000	0%	80%	1334
Bulgaria	4,000,000	0%	80%	893
Croatia	2,500,000	0%	80%	558
Cyprus	450,000	0%	80%	100
Czech Republic	5,700,000	0%	80%	1272
Denmark	3,280,000	100%	-	-
Estonia	709,000	100%	-	-
Finland	3,300,000	100%	-	-
France	35,000,000	95%	-	-
Germany	47,900,000	31%	49%	6,615
Greece	7,000,000	80%	-	-
Hungary	4,063,366	0%	80%	907
Ireland	2,200,000	100%	-	-
Italy	36,700,000	99%	-	-
Latvia	1,089,109	95%	-	-
Lithuania	1,600,000	0%	80%	357
Luxembourg	260,000	95%	-	-
Malta	260,000	100%	-	-
Netherlands	7,600,000	100%	-	-
Poland	16,500,000	100%	-	-
Portugal	6,500,000	0%	80%	1451
Romania	9,000,000	100%	-	-
Slovakia	2,625,000	23%	57%	417
Slovenia	1,000,000	0%	80%	223
Spain	27,768,258	100%	-	-
Sweden	5,200,000	100%	-	-
UK	32,940,000	100%	-	-
TOTAL	**276,819,733**	**74%**	**16%**	**14,127**

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

Table 7: Overview of estimated 'net' yearly costs for additional smart meter installation by 2030 considering all alternative options

	BAU = Option 0	Option 1, Option 2	Option 3
2030			
Smart meter (penetration rate)	**74%**	**81%**	**90%**
Additional 'net' cost (considering 15 years, at 3.5%)		**EUR 215 million/year**	**EUR 613 million/year**

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

Cost of demand response

To make demand response and its benefits possible, certain investments in the system are necessary and operational costs will incur. For the activation costs of demand response three classes are defined:

Table 8: Overview of cost components for demand response

Parameter	Cost component	Unit
Variable costs	Costs for loss of production, inconvenience costs, storage losses	EUR/kWh
Annual fixed costs	Information costs, transaction costs, control costs	EUR/kW
Investment costs	Installation of measurement-equipment, automatic measurement for control, communication equipment	EUR/kW

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

Variable costs for demand response are the costs incurred at the consumer for offering demand response. In case of load shifting these costs are considered to be zero since the lost output can be produced later. However, it is possible that demand response causes additional costs for inconvenience or efficiency losses due to partial load operations, however these costs are expected to be minor and not possible to quantify and are therefore not considered in this analysis.

The annual fixed costs are incurred on a regular basis and are not related to the actual use of demand response. Predominantly, these costs relate to administration and to incentivise consumers for demand response. This analysis only focusses on the system costs, therefore the annual fixed costs are assumed zero.

Investment costs are incurred once the demand response potential is activated. Costs of this type include

- Investments in communication equipment both at the consumer side as in the grid. This enables remote sending of instructions to the consumers who then can provide demand response.
- Investments in control equipment are needed to carry out load reductions automatically. With control equipment it is possible to provide demand response upon receipt of a signal.
- Metering equipment is required to be able to verify that the load reduction is achieved.

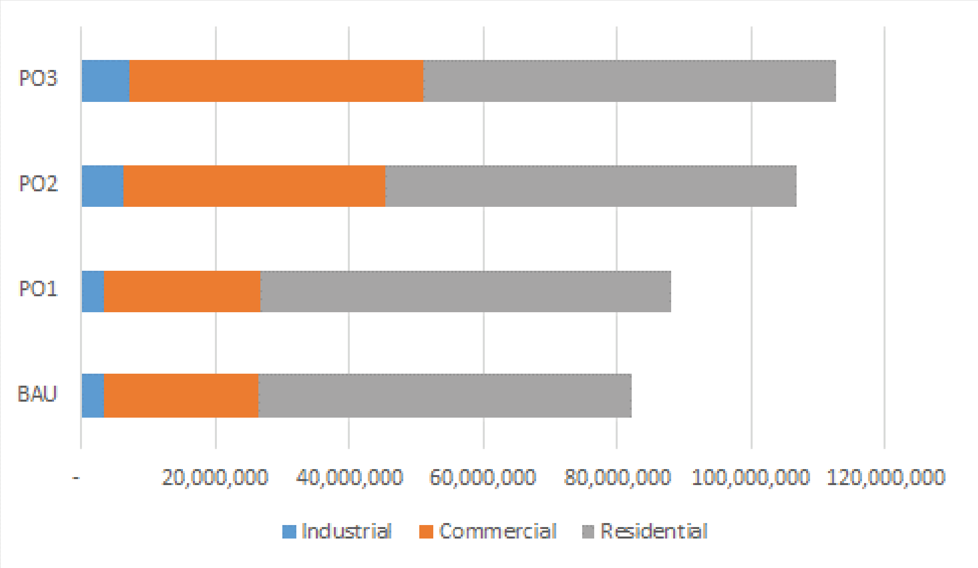
At the moment there is relatively little information available of these investment costs for demand response. Per consumer type, the following assumptions were made:

- **Industrial** consumers often already have equipment installed that can activate demand response. On average, it is however assumed that a very small investment is still required. According to available literature[112], the investments are estimated to be 1 EUR/kW.
- To enable demand response for **residential** consumers, smart appliances must be installed. This means the costs of appliances will be higher. Currently, most new appliances already have an electronic controller which can make the appliance “smart”. However, the appliance also has to be equipped with a communication module, which will typically be either a power line communication (PLC) or a wireless module (such as WLAN or ZigBee). It is assumed that due to mass production of smart appliances in the future, the additional costs will be between 1.70 EUR and 3.30 EUR for all appliances that enable smart operation. Furthermore, costs incur for the smart appliance to communicate with a central gateway in a building. This can be integrated into a smart meter or can be offered as a separate device. The gateway enables communication between the residential consumer and an external load manager or aggregator. The link between the appliances and the gateway (power line or wireless communication) does not require the installation of additional wires. Small additional costs can be assumed due to electricity consumption as a result of standby mode of smart appliances. This is assumed to increase the electricity consumption of the appliance between 0.1% and 2%.
- For **commercial** consumers, the costs for demand response are not available in the literature. Therefore, the costs are derived from the costs of demand response for residential consumers. Because the electricity consumption of commercial consumers is on average higher than the electricity consumption of residential consumers, more load can be shifted. As a result, investments are lower per kW/year. An assumption is made that the costs for commercial consumers will be a factor 6 lower.

In the graph below, the costs of demand response are visualized per Option. As can be seen, the costs are mostly related to the residential sector. This is a result of the higher price per kW that is required to activate demand response.

[112] *"Quantifying the costs of demand response for industrial business"* (2013) Anna Gruber, Serafin von Roon

Graph 3: Costs of demand response in 2030 – comparison of options



Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

Benefits of demand response

Demand response is expected to decrease the peak demand and thereby the maximum needed back-up capacity in the electricity market. The value of a decrease in back-up capacity is expressed as a decrease in yearly CAPEX and fixed OPEX as a function of installed capacity. Demand response also diminishes variable OPEX. When residual electricity demand[113] is averaged (flattened) by demand response, less back-up power needs to be generated by back-up units high in the merit order, and the variable costs of electricity generation will be reduced. Together the decrease in fixed and variable costs determine the estimated value of a demand response option in the electricity market.

Table 9: benefit of demand response for reduced back-up capacity in 2030

	BAU	Option 1	Option 2	Option 3
Total demand response potential 2030 (GW)	34.4	36.8	52.4	57.1
Total Value demand response (million EUR/y)	3517	3772	4588	4736

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

In the distribution grids, demand response options can be deployed to reduce the peak, and thereby the required capacity, in the distribution and transmission networks. These benefits are reflected in a lower required investment in these grids. The benefits shown in the column ‘distribution and transmission’ in the table below are estimated based on existing literature on this topic in combination with the calculations of the overall

113 Residual demand is the demand that remains after subtracting intermittent sources like solar and wind.

possible peak reduction as calculated for the system level. It is shown in modelling exercises that to a large extent peak reduction at the system simultaneously reduces peaks in the distribution grids. This makes this peak demand reduction a good starting point for estimating the savings in the grids.

To estimate the savings per kW of peak capacity reduced, one needs to distinguish between demand connected on the lower voltage and higher voltage grids. The savings on the higher voltage are lower because only investments in transmission can be avoided. It is assumed that industrial demand is on the higher voltage grids, while domestic and commercial demand response is connected to the medium or lower voltage grids.

The average savings are used to calculate the savings that are made possible by the peak reduction. The results are presented in the table below.

Table 10: Benefits of demand response in the distribution and transmission grid

	BAU	Option 1	Option 2	Option 3
Total peak decrease 2030 (GW)	25.8	28.1	36.4	38.0
Total benefit demand response in distribution and transmission grid (million EUR/y)	980	1068	1383	1444

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

Overall monetary cost and benefits for all Options

On the basis of the costs and benefits as presented above the net benefit of the different options is calculated as summarised in the table below.

Table 11: Costs and benefits of Options for 2030 (in million EUR/year)

	BAU	Option 1	Option 2	Option 3
Costs	**82**	**303**	**322**	**328**
Benefits				
Network	980	1068	1383	1444
Generation	3517	3772	4588	4736
Total	**4497**	**4840**	**5971**	**6180**
Net benefit (compared to no demand response)	**4415**	**4537**	**5649**	**5852**
Net benefit (compared to BAU)		**122**	**1234**	**1437**

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

Using the approach described above, the net benefits of the alternative Options compared to BAU amounts to about 120 MEUR/y for Option 1230 MEUR/y for Option 2 and around 1430 MEUR/y for Option 3. The net benefit includes the estimated savings in generation and network capacity.

What is not included in the estimation of the benefits are the possible effects on system costs, if the independent demand aggregators are free riders not baring any balancing responsibility and hence risk to activate the demand response in an inefficient way: for example by bidding in the wholesale market but in the balancing markets where the price might be higher. This could happen under Option 3 where no compensation between aggregators and BRPs is foreseen, and hence the aggregators have no incentive to achieve balance as early as possible in order to improve the overall efficiency.

What is equally not directly included in this calculation are reduced electricity prices in the wholesale market due to demand response. However, those cost reductions are indirectly included in the reduced generation costs.

The follow-on or indirect effects depend on how the savings are distributed among the different actors. In competitive retail markets the major share of these savings will go into lower electricity bills for the consumers. Lower electricity costs will increase welfare for the residential consumers and increase competitiveness for industrial and commercial consumers. However, in less competitive markets suppliers may profit from those price reductions.

CO_2 emission reductions

Next to the monetary impact also CO_2 reductions can be achieved through a greater uptake of demand response. Those impacts can add up to additional savings 1.5Mton/year by 2030 compared to the BAU scenario.

Table 12: Impact on CO_2 – reduction in CO_2 emissions in Mton/y

	BAU	Option 1	Option 2	Option 3
Reduction in CO_2 emissions in Mton/y	12.4	13.0	12.7	12.4[114]

Source: "Impact Assessment support Study on downstream flexibility, demand response and smart metering" (2016) COWI

c. Simplification and/or administrative impact for companies and consumers

The measures proposed under Option 2 and 3 are designed to reduce market barriers for new entrants and provide a stable framework for them under which they can operate in the market. This is a necessity for new entrants who currently face great difficulties entering the markets as incumbent suppliers do not allow them to engage with their customers. The removal of such barriers is especially important for start-ups and SMEs who typically offer innovative energy services such as demand response.

114 For options 2 and 3 the CO_2 benefits are less than for option 1, even if their total DR potential is higher. This can be explained as follows: By applying DR, the peak demand will be diminished and less power is generated by back-up units high in the merit order (e.g. gas plants). But at the same time some low demand values will become higher after DR is implemented (we assume the total demand does not change) and more power is generated by back-up units lower in the merit order (e.g. lignite plants).

Equally for consumers all measures are designed to facilitate their access to innovative products and services. Those measures should reduce the administrative impact for consumers to get a fully functional smart meter and sign service contracts with third parties. At the same time the measures also require Member States to clearly define roles and responsibilities of aggregators which also increases confidence for consumers in their services and contributes to consume protection.

Moreover, thanks to a wider deployment of smart metering, under options 1, 2, and particularly Option 3, the distribution system operators will be in a position to lighten and improve some of their administrative processes linked to meter reading, billing, dis/reconnection, switching, identification of system problems, commercial losses, while at the same time offer increased customer services. Furthermore, a wider roll-out of smart metering would allow TSOs to better calculate, and improve their processes, for settlements and balancing penalties as the consumption figures can be based on real consumption data and not only on profiles.

d. Impacts on public administrations

Regarding **smart metering**, there will be impacts on public administration, namely on the Member States' competent authorities including the national regulators.

Those 17 Member States that roll-out smart meters will not be affected by provisions on smart meters, under **all options,** apart from the obligation to comply with the recommended functionalities, which they may need to transpose into national legislation. Similarly, those two Member States that opted for partial roll-out are not expected to face any major additional impacts from allowing additional consumers to request smart meters, under **Option 1 and 2**. However, they will be impacted when enforcing a mandatory roll-out under **Option 3** which will require substantial changes in their legislation as it currently stands. The remaining Member States that currently do not plan to install smart metering in their territory will need to establish legislation with technical and functional requirements for the roll-out – under any of the options – and face some additional administrative impact for re-evaluating their cost-benefit analyses.

Similarly, additional administrative impact may be created for the national regulatory authorities (NRAs) for enforcing actions regarding the consumer entitlement to request a fully functional smart meter. This includes assessing the costs to be borne by the consumer, and overseeing the process of deployment. At the same time, improved consumer engagement thanks to smart metering, would make it easier for NRAs to ensure proper functioning of the national (retail) energy markets.

No additional impact on public administration is expected from facilitating incentive based demand response as it is just a further specification/guidance on what is already an obligation under EED.

e. Trade-offs and synergies associated with each option with other foreseen measures

Promoting a wider-scale deployment of smart metering with fit-for-purpose functionalities is in line with the Commission's policy objectives namely to put the consumer at the core of the EU's energy system, given that:

– interoperable smart metering systems, equipped with the right functionalities, and connectivity to support novel energy services, are considered essential under the

Energy Union Strategy for bringing tangible benefits to consumers and delivering the "new deal";

- through smart metering, consumers can clearly experience the internal energy market working for them based on their preferences/choices, as it:
  - enables them to get accurate and frequent feedback on their energy consumption;
  - minimize errors and delays in invoices or in switching;
  - maximize their benefits from innovative solutions for consumption optimization (e.g. via demand response) and from emerging technologies (such as home automation); and ,
- reduce the costs of the operation and maintenance of energy distribution infrastructure (ultimately born by consumers through distribution tariffs).

Mandating the minimum functionalities for smart metering will clarify the need to go beyond the capability of delivering just 'actual time of use' information currently mentioned in the related provisions of the Energy Efficiency Directive.

Furthermore, the proposed smart metering functionality to collect meter data at intervals at least equal to the market settlement frequency will support trading and the harmonisation of balancing markets.

In addition to bringing tangible benefits to consumers, further developing demand response is fully coherent with the objectives of other priorities in the field of energy policy as an appropriate market framework for demand response:

- is an enabler for integrating renewables efficiently into the electricity system. It also contributes to render energy storage and self-consumption viable;
- is a key factor for increasing energy efficiency with savings of final but mainly primary energy;
- is a key factor in promoting new products in balancing markets where new rules are being elaborated under the Market Design Initiative to increase competition;
- may help to reduce the need for creating capacity markets and will therefore be considered under the rules for capacity markets to be proposed under the Market Design Initiative;
- will be needed to make efficient use of existing networks and thereby is at the core of the proposal concerning new distribution tariff rules;
- will likely trigger the deployment of smart homes and smart buildings technologies while these will *vice-versa* increase the interest of residential and commercial consumers in participating in demand response programmes. This deployment is foreseen to be supported by measures to be adopted under the Ecodesign/Energy Labelling Framework and by new approaches for smart buildings to be proposed in the context of the review of the EPBD in 2016.

f. Uncertainty in the key findings and conclusions and how these might affect the choice of the preferred option

The analysis on smart metering systems and especially demand response contains a lot of uncertainty. For smart metering systems detailed national cost-benefit analyses have been carried out in 2012. However, the underlying assumptions especially with regard to technology costs that are significantly decreasing may change over time. Also the potential benefits in terms of system and consumer benefits are subject to change depending on technology development, the further integration of decentralised renewable energy generation and upcoming offers for consumers taking part in demand response schemes. Considering the above it is not unlikely that currently the costs for smart metering are over- and the benefits under-estimated in some national cost-benefit analyses.

For incentive based demand response the uncertainty is even greater. Relatively good estimates can be made about the theoretical potential of demand response (see chapter 2 of this annex) where most of the theoretical potential lies with the residential sector. However, the technical and economic potential in the residential sector depends on a number of external factors that are hard to quantify:

- The willingness for residential consumers to engage in demand response. Pilot projects have proven that consumers do engage in the market and adjust their consumption if the incentives are right. These incentives are not always monetary but can also be related to access to advanced information or energy managing tools. However, it is impossible to transfer the results of pilots with engaged consumers to the broad majority of consumers;
- The uptake of heat pumps and electric vehicles that provide considerable shift-able load will most probably determine if a huge number of residential consumers will engage in demand response schemes. However, the uptake of those technologies is yet uncertain;
- Experiences from the Nordic market are not easily transferable to all EU markets as the shifting potential in Finland is relatively high due to e.g. electric heating;
- Experiences from the US market are equally not easily transferable to Europe as the US market design is different. Furthermore wholesale peak prices are higher and more frequent than in Europe. Hence, the economic value of demand response in the US is higher than in the Europe.

The above indicates that the amount of the monetary benefits under the different options is rather uncertain. The figures therefore rather indicate the magnitude of the potential benefits under the different options.

As outlined earlier in this chapter there is also great uncertainty about the results calculated for Option 3 in this impact assessment:

- The analysis only covered the EU as a whole and did not look into national impacts of a mandatory roll-out. It equally assumes the same cost of smart meters and their roll-out across the EU. Therefore it cannot be excluded that in some Member States the costs of a mandatory roll-out of smart meters exceeds its benefits as it was concluded in some national cost-benefit assessments;
- The analysis also did not quantify the potential system impact if independent aggregators are exempted from financially covering the distortions they induce to the system, e.g. not having any balancing responsibilities.

Therefore, the results of Option 3 are even more uncertain than under the other Options and may very well lead to additional system costs and in some Member States to costs for smart metering systems that are not covered by benefits for the system and/or the consumer.

The uncertainty about the uptake of demand response does, however, not affect the assessment of the preferred option. This option (Option 2) does not foresee any enforced measures on the roll-out of smart meters or on the uptake of demand response. Instead, all measures foreseen under this option are just enabling consumers to have access to the right technologies and access to third party service providers. They also foresee to improve access of flexibility to the markets. Under those framework conditions it will be the market that will show to which degree demand response can play a role as a competitive service. Therefore, Option 2 can be considered as a no regret option.

g. Preferred Option

Flexibility is considered to be instrumental for allowing more renewables into the European electricity system without having to make large investments in conventional back-up generation capacity. Therefore, introducing flexibility to the energy system by accelerating the uptake smart metering systems and of demand response are key elements for realising the Energy Union's objectives.

All three Options are fully coherent with the objectives of the Energy Union and other EU policies. The analysis has proven that all options are suited to accelerate the uptake of smart metering systems and demand response as well as this uptake will lead to significant system benefits and cost savings.

Option 1 supports the objective of increasing efficiency of the energy system by introducing smart meters and dynamic pricing contracts. The Third Package included the promotion of smart meters by requesting Member States to undertake a CBA of smart meters and where the benefit-cost ratio is positive to roll-out smart meters. The realisation of Option 1 means also in Member States where there is no general roll-out, relevant consumers can ask for the smart meter and a dynamic price contract. It hence provides the framework to allow all consumers to take advantage of the technological developments. However, while better enabling price based demand is crucial for incentivising residential consumers to benefit, it is not suited to realise the full benefits demand response can offer. As such realising Option 1 will only lead to increase total demand response in Europe by approximately 7% and lead to net benefits of approximately 120 MEUR/y by 2030 (compared to BAU).

In addition to the measures proposed under Option 1, **Option 2** is specifically addressing incentive-based demand response. Article 15 of the Energy Efficiency Directive already promotes demand flexibility and in that respect includes requirements for promotion of demand response. The additional measures in Option 2 are based on the assessment that in most Member States a complete legal framework for demand response is still missing. The measures in Option 2 aim at providing this framework by creating fair market access for independent aggregators and allow flexibility to be traded in organised markets. The analysis has shown that those measures are indeed suited to increase the uptake of demand response by approximately 52% which leads to system benefits of approximately 1230 MEUR/y by 2030 (compared to BAU).

Box X: Benefits and risks of dynamic electricity pricing contracts

The preferred option (Option 2) is to provide all consumers the possibility to voluntarily choose to sign up to a dynamic electricity price contract and to participate in demand response schemes. All consumers will have equally the right to keep their traditional electricity price contract.

Dynamic electricity prices reflect – to varying degrees – marginal generation costs and thus incentivise consumers to change their consumption in response to price signals. This reduces peak demand and hence reduces the price of electricity at the wholesale market. Those price reductions can be passed on to all consumers. At the same time, suppliers can pass parts of their wholesale price risk on to those consumers who are on dynamic contracts. Both aspects can explain why, according to the ACER/CEER monitoring report 2015, on average existing dynamic electricity price offers in Europe are 5% cheaper than the average offer.

While consumers on dynamic price contracts can realise additional benefits from shifting their consumption to times of low wholesale prices they also risk to face higher bills in case they are consuming during peak hours. Such a risk is deemed to be acceptable if taking this risk is the free choice of the consumer and if he is informed accurately about the potential risks and benefits of dynamic prices before signing up to such a contract.

Under **Option 3** a mandatory roll-out of smart meters to at least 80% of consumers in all Member States is included. In addition it is assumed that under this option aggregators do not have to cover the costs they induce to the system and hence do not pay any compensation to BRPs. In terms of uptake of demand response (more than 100% compared to BAU) and overall system benefits (1430 MEUR/y by 2030) this is the most favourable option. However, there are also other impacts that need to be considered in this respect:

- This analysis did not take into account national differences in the costs/benefits of smart meter roll-out but instead average figures were used. This approach does hence not exclude the possibility that the overall economic impact of a mandatory smart meter roll can be negative in some Member States as already suggested in national cost-benefit analyses;
- The exclusion of any compensation mechanism introduces a possibility of demand aggregators being free riders in the markets and therefore creating inefficiencies. This is not in line with the EU target model and generally not in line with creating a level playing field for competition.

Option 2 is considered to be the preferred option, considering that

- the modelling used for this Impact Assessment did not account for national differences and did not calculate the impacts per Member State;
- national cost-benefit analyses suggests that in some Member States mandatory roll-out of smart meters yields negative net benefits; and that,
- the overall banning of any financial obligations by independent aggregators may lead to market distortions with unknown overall impacts.

3.1.6. *Subsidiarity*

The options envisage to give consumers the right to a smart meter with all functionalities and access to dynamic electricity pricing contracts (Option 1) and in addition further specify the roles and responsibilities of third parties offering demand response services (Option 2). These actions promote the interests of consumers and ensure a high level of consumer protection, and have their legal basis in Article 114 of the Treaty and Article 194 (2) TFEU. The policy measures considered under Option 3 can be based on the same provisions.

Option1

- The principle of subsidiarity is respected and EU action is justified as access to smart metering systems is fundamental to improving the functioning of the internal electricity market;
- Ensuring universal consumer rights in the EU electricity markets includes the right to actively engage in the market. This is only possible if technologies enabling innovative energy services are available to all consumers across all Member States.

As stated earlier, for consumers to directly react to price signals on electricity markets, and enjoy benefits coming from the provision of new energy services and products, they must have access to both a fit-for-purpose smart metering system as well as an electricity supply contract with dynamic prices linked to the spot market. However, today this is only a reality in the Nordic Member States and Spain. In addition, under current national smart metering rollout plans till 2020, more than 30% of EU consumers could be excluded from access to such metering systems. The Commission's objective is to ensure that consumers have access to all the prerequisites necessary to be rewarded for reacting to market signals.

This cannot be achieved sufficiently by Member States acting along. Therefore, it is herein proposed to table provisions that will give each consumer, throughout the EU, the right to request the installation of, or the upgrade to, a smart meter with all 10 functionalities proposed in the Commission Recommendation on preparations for the roll-out of smart metering systems[115], while ensuring that consumers fairly contribute to associated costs. Furthermore, it needs to be ensured that every consumer has the choice to select a dynamic price contract linked to the prices at the spot market.

Action at EU level is relevant given that the current EU provisions, which leave the roll-out of smart metering to the Member States' discretion based on the results of their cost-benefit analysis, led to a fragmented, and even not necessarily functionally suitable in all cases, deployment of smart metering.

Actions by Member States alone cannot ensure a harmonised level of consumer rights (right to a smart meter that would enable customers access certain energy services) to the extent to which under current national smart meter rollout plans for 2020, more than 30% of EU consumers could be excluded from access to such metering systems. The right to a smart meter with all the ten recommended functionalities is a precondition for consumers to access energy services[116] that require accurate and frequent billing information such as demand response or electricity supply contract with dynamic prices linked to the spot market.

The costs of rolling out smart meters - with all the benefits that this can bring for consumers, network and energy companies, the energy system as well as society and the environment more widely - will greatly increase if the economies of scale of the EU's internal market are not properly leveraged. Regional differences have already risen with respect to functionality and interoperability of the systems being rolled out, which may result in set-ups that are not necessarily interoperable at national level, or within the EU. This adds complexity and costs to those, be it for instance energy services/product developers or aggregators, who would like to trade in different European countries and optimise their business model. It points to the need to harmonise to a certain extent system requirements and functionalities of smart electricity meters.

In the context of completing the EU's internal electricity market and making retail work also for consumers, it is highly relevant to ensure at EU level a degree of consistency and alignment, as well as gain momentum, in the deployment and use of smart metering throughout Europe. Furthermore, ability to access novel energy services and products

[115] For example, provide readings directly to the customer and any third party designated by the consumer, include advance tariff structures, time-of-use prices and remote tariff control, provide secure data communications, etc. These also carry a host of other benefits such as improved consumer information, enabling self-generation to be rewarded, and delivering flexibility to the system.

[116] e.g. demand response, self-consumption, self-generation

should be indiscriminately offered to all EU citizens. This is what this action – giving the right to request the installation of, or the upgrade to, a smart meter - is meant to deliver.

Such an action will eliminate ambiguities and strengthen the existing provisions, in order to give certainty to those planning to invest, and ensure that smart metering roll-outs move in the right direction, and regain EU added-value, by namely (i) safeguarding common functionality and sharing best practices; (ii)ensuring coherence, interoperability, synergies, and economies of scale, boosting competitiveness of European industry (both in manufacturing and in energy services and product provision), and (iii) ultimately delivering the right conditions for the internal market benefits to reach also consumers across the EU.

Option 2

EU intervention can be justified for several reasons, among them are:

- To improve the proper functioning of the internal market and avoid the distortion of competition in the field of retail energy services and hence fully enable demand response
- To empower consumers by enabling them to take advantage of the well-functioning retail energy markets by easily accessing demand response services under transparent and fair conditions.

Divergent national approaches related to the development of demand response services, or the lack thereof, led to different national regulatory frameworks, raising barriers to entry across borders to demand response aggregators. This initiative complies with the principle of subsidiarity, as Member States on their own initiative would not be able to remove the barriers that exist between national legislations to independent demand response service-providers and to create a level playing field for them.

Each Member State individually would not be able to ensure the overall coherence of its legislation with other Member States' legislations. This is why an initiative at EU level is necessary. It will reduce costs for businesses as they will no longer have to face different national regimes. It will create legal certainty for businesses which want to provide demand response services in other Member States. Common rules are also crucial when e.g. balancing markets will be opened for cross-border trade of flexibility.

Moreover, the present initiative will add value to other measures in the Market Design Initiative. Other measures aimed at empowering customers, such as right to a smart meter and to a dynamic ricing contract, will create new opportunities for European consumers and energy service companies. These opportunities can only be exploited to their maximum extent if they are completed by an initiative on addressing market barriers to aggregators, so that they are able to provide customers with access to demand response services.

Action from Member States alone is likely to result in different sets of rules, which may undermine or create new obstacles to the proper functioning of the internal market and create unequal levels of consumer rights in the EU. For example, a framework for demand response for households is currently being developed in France, while in other Member States there are currently no established rules for demand response aggregators targeting household consumers. Common standards at EU level are therefore necessary to promote efficient and competitive conditions in the retail energy sector for the benefit of EU consumers and businesses.

An initiative at EU level would ensure that consumers in all Member States would benefit from demand response services under harmonised conditions. It would also help removing entry barriers for new service providers (aggregators), including cross-border, therefore stimulating economies of scale and setting the basis for developing flexibility markets at regional level. Such services have a cross-border development potential (e. g. Energy Pool is already active in more than one EU Member States – France, UK).

Option 3

The same arguments to justify EU action as for Option 1 and 2 can be used for the policy measures under Option 3. However, what concerns smart metering there could be doubts that a mandatory roll-out of smart meters with all recommended 10 functionalities conforms to the principles of subsidiarity and proportionality. This is especially relevant as Member States have already conducted national cost-benefit analyses on smart meter roll-out. In 11 Member States those CBAs have unveiled that under current conditions the costs of a roll-out exceed the benefits. In the Commission's analyses no evidence has been found that those national CBAs or their underlying assumptions could be contested or that economies of scale realised by a European roll-out would render the roll-out economically viable. Hence, a mandatory roll-out would effectively impose undue costs on those Member States where the CBAs have been negative. However, the underlying assumptions of those CBAs are likely to change over time with technology cost expected to decrease which may lead to viable roll-outs in the near future.

The principle of proportionality may equally be contested for strict harmonisation of the legislative framework for independent aggregators and demand response. A certain degree of freedom for Member States to design the framework for demand response according to the national design of the markets may indeed have a similar impact than fully harmonised rules.

3.1.7. *Stakeholders' opinions*

Outcome of the public consultation

Result of public consultation Energy Market Design

The consultation on the market design contained one question on demand response:

> *"Where do you see the main obstacles that should be tackled to kick-start demand response (e.g. insufficient flexible prices, (regulatory) barriers for aggregators / customers, lack of access to smart home technologies, no obligation to offer the possibility for end customers to participate in the balancing market through a demand response scheme, etc.)?"*

Many stakeholders identified a lack of dynamic pricing (more flexible consumer prices, reflecting the actual supply and demand of electricity) as one of the main obstacles to kick-starting demand side response, along with the distortion of retail prices by taxes/levies and price regulation. Other factors include market rules that discriminate consumers or aggregators who want to offer demand response, network tariff structures that are not adapted to demand response and the slow roll-out of smart metering. Some stakeholders underline that demand response should be purely market driven, where the potential is greater for industrial customers than for residential customers. Many replies point at specific regulatory barriers to demand response, primarily with regards to the lack of a standardised and harmonised framework for demand response (e.g. operation and settlement). [117]

In total, eleven Member States responded to the question with ten putting specific emphasis on the need for effective price signals that reflect price developments at the wholesale market and incentivise consumers to adjust their consumption. In addition, seven Member States highlighted the need for market rules that allow demand response to participate in wholesale, balancing and capacity markets on equal footing with generation. Also environmental NGOs have been widely supportive of demand response stressing the need for demand side measures to efficiently integrate renewables to the system. Therefore, they call for opening the markets for flexibility. Some organisations call for intensified R&D in the area and/or support schemes while one organisation also calls for targets for demand response. However, Member States and other stakeholders see demand response as a market driven service for which no specific support but fair market conditions is needed. More detail on the opinion of main stakeholders is presented under the individual stakeholder organisations.

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[117] IEA "*Re-powering markets*" (2016) suggests*: Reform of retail pricing is urgently needed to better reflect the underlying cost level and structure. Current tariff and taxation structures which do not vary with time can lead to inefficiencies. Investments in distributed resources are not always cost-effective as bill savings do not properly reflect the avoided costs to the electricity system. The significant difference in speed between installing solar PV and small-scale storage and building large-scale power infrastructure can exacerbate this problem*."

Result on public consultation on the Review of Directive 2012/27/EU on Energy Efficiency

The consultation addressed a number of questions on metering with one specifically addressing electricity smart meters and hence is immediately relevant to this impact assessment:

"Do you think that

- *the EED requirements regarding smart metering systems for electricity and natural gas and consumption feedback and*
- *the common minimum functionalities, for example to provide readings directly to the customer or to update readings frequently, recommended by the Commission together provide a sufficient level of harmonisation at EU level? "*

37% shared the view that the EED requirements regarding smart metering systems for electricity and natural gas and consumption feedback and that the common minimum functionalities recommended by the Commission together provide a sufficient level of harmonisation at EU level. 36% had no view, and 27% did not think that these provisions would provide a sufficient level of harmonisation.

Several participants explained that smart meters would have to provide more useful information to consumers, potentially in 15 minute intervals, or even in real time. Some also suggested that consumers could receive a notification once every three months with an overview on whether they are saving energy and hence money, or whether they are consuming more than would be expected. Yet others noted that the above factors largely depend on market conditions, and on how providers interact with customers. In general, many participants shared the view that EU standards should only apply to minimum ones, as any additional standards could significantly increase the enterprise's complexity. Additionally, several stated that harmonisation must also take into account acceptance by citizens. Finally, some also cited evidence that calls the effectiveness of smart meters in general into question.

Of those 27% who think that the EED requirements regarding smart metering systems for electricity and natural gas and consumption feedback and the common minimum functionalities, recommended by the Commission together do not provide a sufficient level of harmonisation at EU level, 48% share the view that common minimum functionalities should be the basis for further harmonisation. 31% had no view, and 21% did not thing that common minimum functionalities should be the basis for further harmonisation. Some called for additional minimum functional standards to the current ones, for example, monthly or three monthly electronic feedback for consumers on how much energy they are savings. Some participants also argued that the interface of smart meters should be standardised, to facilitate their use. Yet others voiced a shared perception that standards across the EU would be overly determined by utilities.

More detail on the opinion of main stakeholders is presented under the individual stakeholder organisations. While among all respondents the views on the need of additional EU actions was balanced, the opinion of national ministries signal that the majority of Member States believe that the existing provisions are sufficient. Out of 14 replies from Member States only 2 were of the opinion that more harmonisation on EU level would be good to ensure that consumers get the full benefit out of smart meters while 9 consider that the level of harmonisation provided by existing legislation is sufficient and 3 do not state a clear opinion.

European Institutions

Council of the European Union, messages from the presidency on electricity market design and regional cooperation, April 28, 2016, 7876/1/16 REV1

In addition to stakeholders also European Institutions in response to the communications *"Launching the public consultation process on new energy market design"* (SWD(2015) 142 final) as well as *"Delivering a new deal for consumers"* (SWD(2015) 141 final) clearly highlighting the need for smart metering systems, demand response and the importance of allowing new market participants (aggregators) to compete in the markets.

European Parliament, Committee on Industry, Research and Energy, Rapporteur: Werner Langen, DRAFT REPORT on 'Towards a New Energy Market Design', 27.1.2016, 2015/2322(INI)

*"The future electricity retail markets should ensure access to new market players (such as aggregators and ESCO's) on an equal footing and facilitate introduction of innovative technologies, products and services in order to stimulate competition and growth. It is important to promote further reduction of energy consumption in the EU and inform and empower consumers, households as well as industries, as regards possibilities to participate actively in the energy market and **respond to price signals**, control their energy consumption and **participate in cost-effective demand response solutions**. In this regard, **cost efficient installation of smart meters and relevant data systems are essential. Barriers that hamper the delivery of demand response services should be removed.**"*

European Parliament, Committee on Industry, Research and Energy, Rapporteur: Theresa Griffin, REPORT on delivering a new deal for energy consumers, 28.4.2016, A8-0161/2016

- *"5. Recalls that the ultimate goal should be an economy based on 100% renewables, which can only be achieved through reducing our energy consumption, making full use of the 'energy efficiency first / first fuel' principle and **prioritising energy savings and demand side measures over the supply side** in order to meet our climate goals…"*
- *"6.b empower citizens to produce, consume, store or trade their own renewable energy either individually or collectively, to take energy-saving measures, to become active participants in the energy market through consumer choice, **and to allow them the possibility of safely and confidently participating in demand response;**"*
- *"33. Stresses that to incentivise demand response, energy prices must vary between peak and off-peak periods, and therefore **supports the development of dynamic pricing on an opt-in basis**, subject to a thorough assessment of its impacts on all consumers; stresses the need to **deploy technologies that give price signals which reward flexible consumption**, thus making consumers more responsive; … reminds the Commission that when drafting the upcoming legislative proposals it should be guaranteed that the introduction of dynamic pricing is matched by increased information to consumers;*
- ***"37. Emphasises that consumers should have a free choice of aggregators and energy service companies (ESCOs) independent from suppliers";***

Committee of the Regions, Opinion of the European Committee of the Regions – Delivering a New Deal for Energy Consumers, 8 April 2016, ENVE VI -/009

- *"3. notes the extremely high number of services and technical solutions that exist or are currently being developed in the fields of management and demand response, as well as in the management of decentralised production. The European Union must ensure that priority is given to encouraging and supporting the development of these tools, assessing their value and impact, whether economic, social, environmental or in terms of energy, and monitoring their usage to make sure that energy is safe, easy and affordable"*;
- *"24. observes that a level playing field should be created for all future players who generate and supply energy and/or provide new services, in order to enable, for example, grid flexibility and integration of energy produced by "prosumers" (including aggregators)"*;
- *"42. reiterates its call to speed-up the development of smart systems at both grid and producer/consumer level, to optimise the system as a whole, as well as to* ***introduce smart meters, which are essential to the efficient management of demand with the active involvement of the consumer****";*
- *"43. calls for the adoption of a strict framework at European level on the deployment of* ***smart meters and their range of uses and features****, whilst recalling that the aim is to streamline and reduce consumption. In this regard, the Committee calls for all new technology options to be evaluated prior to adoption, if they are to be introduced as standard, with regard to their potential energy, economic, social and environmental impact";*

Selected Stakeholder's views

Florence Forum of electricity regulation – Conclusions of 31 meeting on June 13, 2016

The Forum recognises that the development of a holistic EU framework is key to unlocking the potential of demand response and to enabling it to provide flexibility to the system. It notes the large convergence of views among stakeholders on how to approach the regulation of demand response, including:

- The need to engage consumers;
- The need to remove existing barriers to market access, including to third party aggregators;
- The need to make available dynamic market-based pricing;
- The importance of both implicit and explicit demand response; and,
- The need to put in place the required technology.

Regulators (ACER/CEER)

The Agency for the Cooperation of Energy Regulators (ACER) and the Council of the European Energy Regulators (CEER) both welcomed the Commission's energy market design consultation paper of July 2015, and in particular the reinforced steer towards cross-border and market-based solutions, and noted its *"**alignment in thinking**"* with their *Bridge to 2025* proposals and sharing of *"the common aim of* ***establishing liquid, competitive and integrated energy markets that work for consumers***"[118].

They consider that ***"a well-functioning market is characterised by innovation and a range of products offered to consumers"***, which *"can be a sign of healthy competition and innovation in the market"*. Key features of this new consumer-centric energy market model advocated by the regulators[119] rely on *"**near real time frequency of smart metering data for all**"*, and *"**demand response through flexible consumption**"*. The latter translates into "*availability of time-of-use/hourly metering and different pricing schemes offers from suppliers and availability of aggregation services from third-party companies*". To assist realising this, CEER amongst other works towards ensuring that "*most customers have a minimum knowledge of the most relevant features for engaging and trusting the market*", access to *"empowerment tools"* and *"a minimum level of engagement"*, as well as that the *"regulatory framework allows and incentivises the availability of a range of offers"*[120].

CEER when discussing[121] **implicit, or price-based demand response**, it states that *"without smart meters (and optionally in addition other facilitators such as smart appliances)"* and in the absence of **dynamic pricing contracts**, there are *"limited possibilities for retailers to value demand side flexibility in their portfolio optimisation"*. CEER further notes that "*access to contracts that directly link the energy component to wholesale markets with a possible granularity down to hourly-based prices create a bridge between wholesale and retail markets, incentivising consumers to exploit opportunities when prices are low and to adjust consumption when prices are high*".

Furthermore, CEER affirms that *"the **availability of smart metering equipment and systems** which allow time-of-use meter readings **is a pre-requisite for consumers** to be able **to opt into implicit demand response** schemes. Smart meters may also enable explicit demand response services through a dedicated standard interface, either as mandatory equipment or an option"*[122]. But for smart meters to be able to deliver this service, they need to be fit-for-purpose, and therefore equipped with the right functionalities. CEER notes that *"there is a **consistency and convergence** between the work of European Energy Regulators and the European Commission regarding smart*

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118 ACER/CEER common press release *"Energy Regulators (ACER/CEER) welcome the market-based solutions and cross-border focus of the European Commission's energy market design*", 15.07.2015; http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/PRESS_RELEASES/2015/PR-15-07_Joint-CEER-ACER%20PR%20%20-EnergyMarketDesignConsultation_FINAL.pdf

119 CEER presentation at the 12th EU-US Roundtable, 03.05.2016; http://www.ceer.eu/portal/page/portal/EER_HOME/EER_INTERNATIONAL/EU-US%20Roundtable/12th_EU-US_Roundtable/12th%20EU-US%20RT_S4-International_deSuzzoni.pdf

120 idem

121 CEER discussion paper *"Scoping of flexible response"*, 3 May 2016; http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2016/C16-FTF-08-04_Scoping_FR-Discussion_paper_3-May-2016.pdf

122 CEER *"Position paper on well-functioning retail energy markets"*, , 14 October 2015; http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab5/C15-SC-36-03_V19_Well-functioning_retail_markets.pdf

meter functionalities, in particular those which benefit consumers". At the same time, however, CEER does not consider these elements sufficient for providing the necessary level of harmonisation across the EU, *"the issue being that Member States do not apply them". Consequently, CEER are* ***in favour of using the "minimum functionalities as a basis for further harmonisation"***[123].

TSOs (ENTSO-E)

ENTSO-E considers that *"the development of demand-side response (DSR) should ensure that* ***demand elasticity is adequately reflected in short-term price building and long-term investment incentives****. DSR can deliver different types of products and participate in the associated markets with large socio-economic welfare gains*"[124]. Furthermore, ENTSO-E notes that *"the organisation of, and timely access to, metering and settlement data which will be made available by smart meters is essential for facilitating the uptake of DSR"*[125]. Elaborating on that, ENTSO-E states that the full potential can be unleashed if the following requirements[126] are satisfied, namely:

(i)*"****price signals*** *need to reveal the value of flexibility"* for the electricity system;

(ii)"*efficient use of DSR is based on an economic choice between the value of consumption and the market value of electricity. This choice arises when the* ***consumer is exposed to variable prices or*** *if the consumer* ***can sell his flexibility on the market****, possibly with the help of an aggregator*".

(iii) *"****access to price information, consumption awareness*** *and DSR activation require strong consumer involvement, which can be facilitated with* ***automation*** *or by delegating the DSR process from the consumer to a company"*;

(iv) *"****regulatory barriers****, when present,* ***need to be removed*** *to unlock full DSR potential, including barriers related to the* ***relationship between independent aggregators and suppliers****. Any evolution must preserve the efficiency and well-functioning of markets and their design components, such as the pivotal role of balance responsible parties, their information needs and balancing incentives. From a TSO perspective, the choice of the market model results from a* ***trade-off between the imperatives not to increase residual system imbalance and to facilitate the development of additional resources"***;

[123] CEER Response to European Commission Public Consultation on the Review of the Energy Efficiency Directive, 29 January 2016; http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab6/C16-CRM-96-04_EC_PC_EED_Response_290116.pdf

[124] ENTSO-E policy paper "*Market design for demand response*", November 2015; https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/entsoe_pp_dsr_web.pdf

[125] ENTSO-E position paper "*Towards smarter grids: Developing TSO and DSO roles and interactions for the benefit of consumers*", March 2015; https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/150303_ENTSO-E_Position_Paper_TSO-DSO_interaction.pdf

[126] ENTSO-E policy paper "*Market design for demand response*", November 2015; https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/entsoe_pp_dsr_web.pdf

(v)"***DSR should develop itself based on viable business cases.*** *Subsidies should remain limited and clearly identified*";

(vi)"***Communication and control technologies*** *need to enable DSR for small consumers and provide guarantees on their reliability*"**.**

ENTSO-E also clarifies that *"to enable dynamic pricing, settlements must be based on at least hourly metering values"*, which means that *"Member States must phase out static consumption profiles, and introduce time-of-stamped (at least hourly) smart meter readings for consumers*"[127].

<u>*DSOs (CEDEC, EDSO for Smart Grids, EURELECTRIC, GEODE)*</u>

The four DSOs associations appreciate the contribution of demand response towards achieving EU energy objectives, and recognise the need for active customers participating in the markets. They state that[128] *"with the growing uptake of smart grids and distributed energy connected to Europe's distribution grids, DSOs are successfully embracing the 'digitalisation' transformation"*, and are **in favour of *"the procurement of flexibility services in an open market context*** *where everyone, including end users, is welcome to take part."* They have also affirmed in different fora their conviction on the key role that smart metering plays in delivering that function and the accompanying benefits, by providing accurate and secure data on energy consumption, while enabling customers to make smart choices helping them to also save money and energy.

CEDEC

CEDEC considers that[129] *"in order to implement effective demand-response programmes, signals about demand and supply need to be received, managed and communicated to the relevant parties. For this, the development of smart distribution grids is indispensable"*. Moreover, *"for the development of smart grids, cost-reflective regulatory frameworks need to be in place… " giving the right incentives, that should amongst others, "allow for time-differentiated prices, which will* ***give price signals to consumers to shift their consumption*** *from peak to off-peak times*"[130]. Such settings are more complex and in fact "***only possible with a smart meter***"[131].

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127 ENTSO-E *"Recommendations to the regulatory framework on retail and wholesale markets";* Input to EC Market Design Package; 10 June 2016.

128 DSOs Associations' joint event *"Innovative DSOs are needed in a Decentralised Energy System"*, 12.04.2016, http://www.geode-eu.org/uploads/GEODE%20Germany/Stellungnahme/2016/0411%20FINAL%20Joint%20PR%20-%20Innovative%20DSOs%20in%20a%20decentralised%20energy%20system.pdf

129 CEDEC position " *on EC Communication - Delivering the internal electricity market and making the most of public Intervention*", December 2013; http://www.cedec.com/files/default/cedec-position-ec-guidance-package-final.pdf

130 CEDEC publication "*Smart grids for smart markets*", 2014; http://www.cedec.com/files/default/cedec_smart_grids_position_paper-2.pdf

131 CEDEC publication "*Distribution grid tariff structures for smart grids and smart markets*", 2014; http://www.cedec.com/files/default/cedec%20leaflet%20grid%20tariffs-final-140403-1.pdf

EDSO for Smart Grids

EDSO considers that DSOs are at the core of the energy transformation and have *"the **potential to empower consumers** to take a more active part in the energy system, for example, **by rolling-out smart meters**"*[132]. Furthermore, EDSO argues that *"engaging consumers will require appropriate incentives and technologies"*, as well as *"clear price signals", for flexibility markets to develop and demand response to deliver its full benefits"*[133]. EDSO notes that incentives for *"**dynamic tariffs or incentive based demand response**"* should be set up *"in order for the consumer to make savings by offering controllable loads to network operators"*. It also advocates that a *"revision of grid tariffs with time-dependent and site-dependent components or incentive based demand response, is an essential step towards realising the benefits, as well as for passing on the costs of flexibility*"[134].

Furthermore, EDSO states that *"DSOs could make the most of their grid provided that they are allowed to use system flexibility services*"[135]. Moreover, *"**increasing flexibility** in the electricity market (when technically and economically appropriate) would result in a number of benefits for DSOs, consumers (all grid users) and society as a whole*". However, according to EDSO *"this implies that **distribution networks are planned differently**, incorporating new risk margins and uncertainty, are not only managed as they used to be, but rather as networks with enhanced observability, controllability and interactions with market stakeholders"*.

Regarding smart metering functionalities, EDSO claims[136] that the ***"EED requirements and the EC recommendation" on common minimum functionalities*** "have been **useful in assisting the industry identify the most relevant functionalities for smart meters**. *Now that most national deployments are underway or near launch,* ***there is no need for further action from the European Commission***". Furthermore, it notes that *"proposing to further harmonise smart meter systems at this time, beyond the existing EC's recommendations on minimum smart metering functionalities, could further delay smart meter deployment and thus consumers' access to detailed and accurate information on their energy consumption"*.

EURELECTRIC

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132 EDSO report "*Data Management: The role of Distribution System Operators in managing data*", June 2014; http://www.edsoforsmartgrids.eu/wp-content/uploads/public/EDSO-views-on-Data-Management-June-2014.pdf

133 EDSO report "*Flexibility: The role of DSOs in tomorrow's electricity market*", May 2014; http://www.edsoforsmartgrids.eu/wp-content/uploads/public/EDSO-views-on-Flexibility-FINAL-May-5th-2014.pdf

134 idem

135 System flexibility services: any service delivered by a market party and procured by DSOs in order to maximise the security of supply and the quality of service in the most efficient way – Reference: EDSO report " *Flexibility: The role of DSOs in tomorrow's electricity market*", May 2014.

136 EDSO response to the Consultation on the Review of Energy Efficiency Directive, January 2016; http://www.edsoforsmartgrids.eu/wp-content/uploads/160129_Public-consultation-Energy-Efficiency-Review_final_EDSO.pdf

Eurelectric acknowledges that *"demand response will be one of the building blocks of future wholesale and retail markets*", and *"the development of innovative demand response services will empower customers, giving them more choice and more control over their electricity consumption. Phasing out regulated retail prices and* ***rolling out smart meters*** *continue to be* ***key prerequisites*** *to advance demand response further*"[137]. As Eurelectric explains[138] it is *"**fit-for-purpose smart meters**" that are needed and are "... a key tool to empower consumers*". And *"...without prejudice to smart meter rollouts which are already ongoing, it would be* ***important to guarantee that all smart meters across the EU had a minimum agreed common set of functionalities*** *to make sure that they contribute to consumer empowerment and efficient retail markets. Basic common functionalities would include, for example, the possibility of performing remote operations, the capability to* ***provide actual, close to real-time meter readings to consumers****, or the possibility to* ***support advanced tariff schemes****"*[139]. Furthermore, Eurelectric supports the position that *"**smart meters with a reading interval corresponding to the settlement time period are a technical prerequisite** for participation of users (with aggregated flexibility units) in balancing markets*"[140].

To untap the full demand response potential, Eurelectric recommends[141]:

(i) "***ensuring*** *that the* ***demand response value is market-based*** *in order to avoid any extra costs to the system, customers and other actors*";

(ii) *"implementing* ***adequate communication*** *between third party aggregators and balance Responsible Parties (BRPs)/suppliers to ensure that demand response can take place effectively";*

(iii) *"ensuring that BRPs/suppliers are compensated for the energy they inject and that is re-routed by third party aggregators*", and *"to this end, third party demand response aggregators and suppliers agree on the* ***rules of compensation****. Changes in market rules and settlement adjustments could also be implemented. In addition, a* ***clear balance responsibility of third party aggregators*** *is needed*";

(iv) *"ensuring that, on a commercial basis, BRPs/suppliers are able to* ***renegotiate supply contracts*** *to take into account the indirect effects of demand response (e.g.* ***rebound effects****) and consequent impacts on sourcing costs*"; and

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137 Eurelectric report "*Designing fair and equitable market rules for demand response aggregation*", March 2015; http://www.eurelectric.org/media/169872/0310_missing_links_paper_final_ml-2015-030-0155-01-e.pdf

138 Eurelectric report "*The power sector goes digital - Next generation data management for energy consumers*", May 2016; http://www.eurelectric.org/media/278067/joint_retail_dso_data_report_final_11may_as-2016-030-0258-01-e.pdf

139 idem

140 Eurelectric report "*Flexibility and Aggregation – requirements for their interaction in the market*", January 2014; http://www.eurelectric.org/media/115877/tf_bal-agr_report_final_je_as-2014-030-0026-01-e.pdf

141 Eurelectric report "*Designing fair and equitable market rules for demand response aggregation*", March 2015; http://www.eurelectric.org/media/169872/0310_missing_links_paper_final_ml-2015-030-0155-01-e.pdf

(v) *"facilitating demand response aggregation at distribution network level through information exchange between DSOs, TSOs and aggregators, for example* ***using a system that reflects network availability***".

GEODE

The association for the local energy distributors GEODE identifies the non-wide deployment of smart metering as one of the main barriers for demand response taking off, stating that there is *"...****no demand response and actual consumption data without smart meters*** *- which are still being rolled-out in many Member States"*[142]. Furthermore, it argues that *"...demand side flexibility* ***aggregators should have access to balancing markets on a level playing field with other parties****"*, and that *"...the* ***end customer should participate*** [in demand response schemes] ***on a voluntary basis only****"*.

Moreover, even though GEODE recognises the need, as stated in different fora, to ensure that smart metering systems with the right functionalities are rolled out to support demand response, it cautions on the making a set of functionalities binding without at least foreseeing a transition period for implementation. Following a survey that the association undertook among its members on the use of the common minimum functionalities for smart metering systems recommended by the Commission, it acclaimed[143] that *"... in those countries where the roll-out has just started or is still in a planning phase, almost all requirements as recommended by the European Commission are implemented"*. However it continues, *"...if the European Commission is considering* ***making binding the recommendations on smart meter functionalities*** […] ***these should apply for the next generation of meters to be rolled-out****. At least, a* ***sufficient transitional period should be provided*** *which is as long as the expected lifetime of the smart metering systems already installed respectively smart metering systems which are going to be installed in the next years - tenders are currently running or the roll-outs have recently started with the objective to reach the 2020 target of 80%. Otherwise it would – once again - require huge investments to be made by DSOs for replacing existing meters."*

Suppliers (Eurelectric)

Suppliers state that *"while demand response has been and could continue to be deployed by suppliers without* ***smart metering*** *or connected appliances, these technologies* ***will***

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[142] GEODE Comments to the European Parliament Draft Report on "*Delivering a New Deal for Energy Consumers*", http://www.geode-eu.org/uploads/GEODE%20Germany/DOCUMENTS%202016/GEODE%20Final%20Comments%20-%20EP%20Draft%20Report%20New%20Deal.pdf

[143] GEODE Position paper sent to EC services, dated 20/04/2016, entitled: "GEODE Survey – to assess whether EC common minimum functional requirements for smart metering systems for electricity - EC Recommendation of 9 March 2012 on preparations for the roll-out of smart metering systems (2012/148/EU) are implemented by GEODE member companies"

facilitate more advanced dynamic pricing and new demand response services"[144]. They recognise the benefits that the advent of smart metering, smart devices and overall digitisation of the energy sector will bring in this respect, and how it will change their interaction with consumers taking into a new level *"changing their traditional business models, based on pure delivery of kilowatt-hours towards* ***becoming full service providers"***[145]. Suppliers will *"have access to new data sources and tools to communicate with their customers and better understand their needs"*. Furthermore, they *"…will (also) be able to provide consumers with information on - and prediction of - their energy usage and consumption patterns, even breaking it down into* ***close to real-time information****…through extra devices"*, and enable the delivery to them of *"****more personalised offers and services*** *by market players"*. This includes the proposition of *"****innovative demand response or time of use tariffs*** *which* ***contribute to the efficient operation of the energy system whilst being financially attractive****,* ***transparent and guaranteeing a given level of comfort to consumers*** *through remote steering of connected appliances."*

At the same time, utilities consider that despite their experience in collecting and processing meter readings, *"dealing with more granular data generated by smart grids and meters will carry a higher level of complexity"*, while competition in shaping and trading novel energy products to consumers *"will intensify from all sides"*, including from new actors. Suppliers welcome the changes that are coming but recognise that they *"will have to proactively find their place in this new ecosystem"*.

Aggregators (SEDC)

The Smart Energy Demand Coalition (SEDC) advocates that demand-side resources can play a crucial role in making the transition to a decarbonised energy system efficient and affordable, and also involving in this empowered energy consumers. SEDC believes that *"****a precondition for consumer empowerment is giving them a choice****: citizens, commercial and industrial consumers should be able to opt for the energy services they prefer, the services they wish to sell, and the service provider they wish to work with. This* ***includes the choice to valorise the flexibility of their devices and processes on the market****, the choice to self-generate electricity, or the* ***choice for real-time electricity pricing*** *to adjust parts of their consumption – automated or not – to the variability on the market and save costs. It also includes the* ***choice to work with*** *their energy supplier as well as* ***an independent energy service provider*** *such as a demand response aggregator for different services"*[146]. For this to happen, SEDC recommends a set of *"coherent measures to remove barriers currently in place and implement a long-term vision for*

[144] Eurelectric brochure "*Everything you always wanted to know about Demand Response*", 2015; http://www.eurelectric.org/media/176935/demand-response-brochure-11-05-final-lr-2015-2501-0002-01-e.pdf

[145] Eurelectric report *"The power sector goes digital - Next generation data management for energy consumers"*, May 2016; http://www.eurelectric.org/media/278067/joint_retail_dso_data_report_final_11may_as-2016-030-0258-01-e.pdf

[146] Article by F. Thies SEDC Executive Director appearing under "*Guest Corner*" in EC DG ENER Newsletter of May 2016; https://ec.europa.eu/energy/en/energy_newsletter/newsletter-may-2016

consumer engagement"[147], and advises that *"**the potential of demand-side flexibility (is) adequately included in all European scenario calculations and planning for infrastructure developments**".*

Amongst its recommendations, SEDC lists the following:

(i) *"EU rules providing for access for demand-side flexibility to all energy markets (wholesale, balancing, ancillary services and capacity) on an equal footing with generation"*, and **enabling *"customers … to participate in all markets directly or through an aggregator*"**;

(ii) *"**third party aggregators** should **access all markets without prior agreement of** the respective customer's **energy retailer/Balance Responsible Party**"*; and ***"market prices should reflect the real value of electricity at any moment"***;

(iii) ***"any customer should have the right to a smart meter and to choose hourly, and where applicable quarter-hourly, market pricing;** the retailer/BRP should be settled accordingly"*;

(iv) *"**Distribution System Operators should be encouraged to make use of smart demand-side flexibility solutions** offered by market parties for system operations purposes. **Incentive structures** should be revised to this end"..., "... **network tariffs** should support, rather than hamper the use of demand-side flexibility, and perverse incentives must be removed".*

Consumer Groups

BEUC – the European Consumer Association, advocates that as we are moving towards a consumer-centric energy market, we need to ensure that we address both old and new challenges – with the latter being new technologies (smart meters, connected devices, smart homes), friendly demand-side response and new business models and new market players. BEUC believes that *"**increased consumer engagement is an important factor for the future energy sector**. This **requires innovative ideas** to empower consumers **backed by an appropriate legal framework"***. Also, *"new products and services **need to respond to consumers' demands rather than risk confusing them** further. Moreover, as new technologies*[148] *make it technically possible to process much more data than as is current practice in the energy sector, compliance with **data protection** rules and their enforcement must be ensured"*[149].

BEUC feels that these technologies *"in general **may offer a larger choice of products and services** as well as more information for consumers, **yet the benefits for consumers are not guaranteed**"*[150]. It clarifies its rationale by noting that *"although new*

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[147] SEDC position paper "*10 Recommendations for an Efficient European Power Market Design*", 2016; http://www.smartenergydemand.eu/wp-content/uploads/2016/02/SEDC-10-recommendations.pdf

[148] E.g. smart meters, varying user interfaces, smart appliances and home automation

[149] BEUC website - http://www.beuc.eu/press-media/news-events/energy-union-what-it-consumers

[150] BEUC position paper "*Building a consumer-centric energy union*", July 2015; http://www.beuc.eu/publications/beuc-x-2015-068_mst_building_a_consumer-centric_energy_union.pdf

*technologies such as smart meters may help those who consume large amounts of electricity ..., **smart meters should not be understood as a necessity to achieve energy savings**. Therefore, instead of pushing through this technology, **new services** (facilitated by new technologies) **or demand response programmes should be based on understanding market opportunities and consumer outcomes**. Consumers should also have the **right to opt out** and have their meter operated in dumb mode. A **voluntary and consumer-centred roll-out of smart meters rather than a mandatory one** may increase consumer participation and public support as it facilitates ownership, data protection, security and cost allocation issues. Moreover, where smart meters are rolled out, **minimum functionalities and interoperability are essential** to ensure consumers have easy access to the information they need to take informed decisions on their consumption, but this is only the starting point. Further work is needed to build trust and encourage consumer engagement. Consumers urgently need **clear commitments that the investments** to upgrade the infrastructure and the roll-out of smart meters **will deliver benefits to them as well as monitoring and enforcement of these commitments"***. BEUC therefore calls for *"a solid legal and regulatory framework" "...in order to guarantee that the roll-out is cost efficient and that **costs and benefits are fairly shared among all stakeholders who benefit from the new technology"***. At this point BEUC also notes that *" the benefits to DSOs from smart meters in regard to running, surveillance, repairing and planning the network is often undervalued when setting the share of costs covered by consumers via their bills".*

Regarding demand response, and looking at what the near future can bring to households in terms of demand response, BEUC states that a *"smart demand response scheme"* that can be of interest to consumers should be *"transparent (simple and clear offers and contracts); voluntary; rewarding flexibility and not penalising in-flexibility", "focus(ed) on consumers' needs and experience"*[151]. In fact **to guarantee consumers can benefit from demand response**, BEUC sees that[152]

(i) *"**transparency and comparability** are key to the success of new dynamic tariffs"*;

(ii)it is important to assess *"the degree to which consumers will likely rely on **automation** to deliver the expected benefits and ... how (novel energy) services (could) accommodate **consumers' lifestyles**"*;

(iii)*"regulators should ensure consumers' flexibility is **properly rewarded** and that there are **price safeguards** when consumers are fully exposed to wholesale market developments"*; and

(iv) calls for the *"European Commission to coordinate with Member States and national regulators a distributional analysis on the **impact of time-of-use tariffs on different social groups** and if/how these groups can access the **benefits of new deals**".*

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[151] BEUC presentation at the EUSEW 2016 event "*Engaged customers driving the energy transition*", 16.06.2016 - http://eusew.eu/engaged-customers-driving-energy-transition

[152] BEUC position paper "*Building a consumer-centric energy union*", July 2015; http://www.beuc.eu/publications/beuc-x-2015-068_mst_building_a_consumer-centric_energy_union.pdf

3.2. Distribution networks

3.2.1. *Summary table*

Objective: Enable Distribution System Operators ('DSOs') to locally manage challenges of energy transition in a cost-efficient and sustainable way, without distorting the market.		
Option: 0	Option 1	Option 2
BAU Member States are primarily responsible on deciding on the detail tasks of DSOs.	- Allow and incentivize DSOs to acquire flexibility services from distributed energy resources. - Establish specific conditions under which DSOs should use flexibility, and ensure the neutrality of DSOs when interacting with the market or consumers. - Clarify the role of DSOs only in specific tasks such as data management, the ownership and operation of local storage and electric vehicle charging infrastructure. - Establish cooperation between DSOs and TSOs on specific areas, alongside the creation of a single European DSO entity.	- Allow DSOs to use flexibility under the conditions set in Option 1. - Define specific set of tasks (allowed and not allowed) for DSOs across EU. - Enforce existing unbundling rules also to DSOs with less than 100,000 customers (small DSOs).
Pro Current framework gives more flexibility to Member States to accommodate local conditions in their national measures.	Pro Use of flexible resources by DSOs will support integration of RES E in distribution grids in a cost-efficient way. Measures which ensure neutrality of DSOs and will guarantee that operators do not take advantage of their monopolistic position in the market.	Pro Stricter unbundling rules would possibly enhance competition in distribution systems which are currently exempted from unbundling requirements. Under certain condition, stricter unbundling rules would also be a more robust way to minimizing DSO conflicts of interest given the broad range of changes to the electricity system, and the difficulty of anticipating how these changes could lead to market distortions.
Con Not all Member States are integrating required changes in order to support EU internal energy market and targets.	Con Effectiveness of measures may still depend on remuneration of DSOs and regulatory framework at national level.	Con Uniform unbundling rules across EU would have disproportionate effects especially for small DSOs. Possible impacts in terms of ownership, financing and effectiveness of small DSOs. A uniform set of tasks for DSOs would not accommodate local market conditions across EU and different distribution structures.
Most suitable option(s): Option 1 is the preferred option as it enhances the role of DSOs as active operators and ensures their neutrality without resulting in excess administrative costs.		

3.2.2. *Description of the baseline*

Legal framework

Article 25 ('Tasks of distribution system operators') of the Electricity Directive puts forward provisions which describe the core tasks of DSOs, as well as, specific obligations that DSOs have to comply with. Under these provisions, DSOs are mainly responsible to operate, maintain and develop under economic conditions a secure, reliable and efficient electricity distribution system.

Except these core tasks, the Electricity Directive sets under Article 25(6) some specific obligations e.g. in cases where DSOs are responsible for balancing the distribution system. Moreover, under Article 25(7), DSOs shall consider measures such as energy efficiency and demand-side management, in order to avoid investing in new capacity.

According to Article 41 of the Electricity Directive Member States are responsible to define roles and responsibilities for different actors including DSOs. These roles and responsibilities concern the following areas: contractual arrangements, commitment to customers, data exchange and settlement rules, data ownership and metering responsibility.

Article 26 of the Electricity Directive set also unbundling requirements for DSOs similar to Directive 2003/54/EC (the previous Electricity Directive which was part of the Second Package). The Electricity Directive sets unbundling requirements in terms of legal form (legal unbundling) where the DSO is a legally separate entity with its own independent decision making board, but remains under the same ownership of a vertically integrated undertaking ('VIU'). Under this form of unbundling it is also required that DSOs implement functional unbundling where the operational, management and accounting activities of a DSO are separated from other activities in the VIU. Article 31 of the Electricity Directive also requires the unbundling of accounts (accounting unbundling) where the DSO business unit must keep separate accounts for its activities from the rest of the VIU in order to avoid cross-subsidisation,.

Article 26(4) of the Electricity Directive gives the option to Member States not to apply the unbundling rules (no legal/functional unbundling) for DSOs with less than 100,000 customers. Only accounting unbundling applies to DSOs below this threshold. Member States may choose to apply this threshold or not, or to set a lower threshold. Article 26(3) contains obligations which seek to strengthen regulatory oversight on vertically integrated undertakings and to mitigate communication and branding confusion.

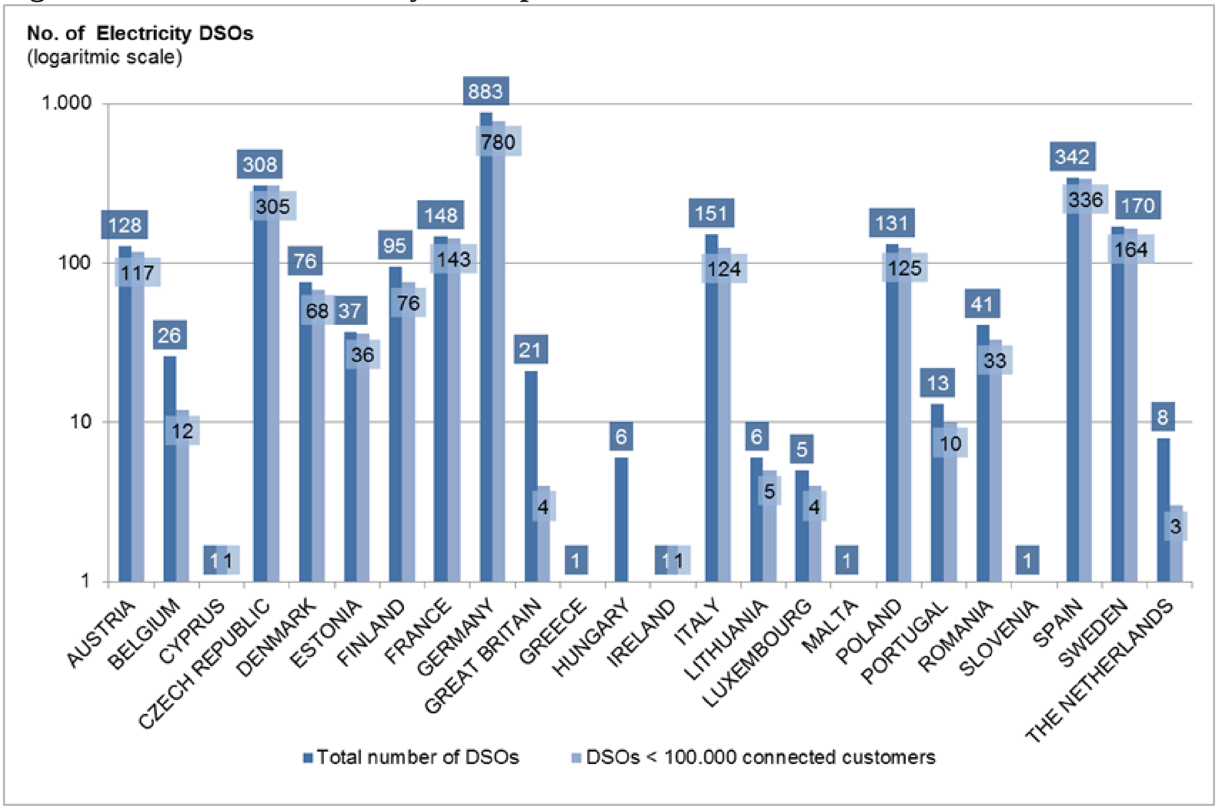
Assessment of current situation

Electricity distribution differs widely across EU Member States in terms of the number of DSOs in each country, voltage level of the distribution system, and tasks. According to CEER[153] (data for 24 EU Member States) there is a total of 2,600 electricity DSOs operating across EU (see figure 1). From these DSOs, 2,347 (around 90% of the total) fall under the 100,000 rule and according to Article 26(4), for these DSOs, Member

[153] *"Status Review on the Transposition of Unbundling Requirements for DSOs and Closed Distribution System Operators"* (2013) CEER.

States are not obliged to implement unbundling provisions under Article 26 of the Electricity Directive.

Figure 1: Number of electricity DSOs per Member State



Source: CEER (2013)

Within the framework of the Electricity Directive, Member States have to determine the detailed tasks of DSOs. There is number of factors which may affect those tasks such as: the structure and ownership of electricity distribution (i.e. public/private, municipalities etc.), development of the electricity sector, size of the DSOs, voltage level of distribution grid. For instance, in Member States with a high number of DSOs two layers of distribution systems usually exist, local distribution systems and regional distribution systems which connect local networks with the transmission network.

According to the Electricity Directive the core tasks of DSOs are to maintain, develop and operate the distribution network. The Electricity Directive does not allocate other specific tasks to DSOs such as for instance metering or data management activities. The more specific activities are left to Member States to decide, according for instance to Article 41. According to the Electricity Directive DSOs may also perform balancing activity, this may be the case in some Member States for regional or larger DSOs.

Therefore, as the EU legislation leaves a quite open framework, there is a variety of tasks for which DSOs are responsible, depending on the Member State where they are operating. For instance, even in activities such as metering and connection that in the majority of the Member States is traditionally performed by the DSOs, there are cases (e.g. UK) where the activity is open to competition.

When it comes to tasks which can be performed both by TSOs and DSOs there is a mixed picture across the EU. In general, tasks such as dispatching of generation and use of flexibility resources are part of TSO tasks. In the majority of Member States where DSOs can be involved in dispatching activities, this is mostly in cases of emergency in order to ensure security of supply. Cases where flexibility resources or interruptible contracts can be used by DSOs are rather limited[154].

In meeting the 2020 targets and 2030 climate and energy objectives[155], Member States will have to integrate a high amount of RES with an increasing number of these resources being variable RES E (wind and solar). A large share of these resources is connected to distribution grids (low and medium voltage); according to available data[156] this number is estimated to be even higher than 90% in some Member States (e.g. Germany) and over 50% in others (Belgium, UK, France, Ireland, Portugal, and Spain).

Moreover, the electrification of sectors such as transport and heating will introduce new loads in distribution networks. These elements will create new requirements and possibilities[157] for DSOs, who will have to manage higher peaks in demand while maintaining quality of service and minimizing network costs.

The degree of the challenge of integrating high amounts of variable RES (VRES) in networks differs among the Member States. A group of Member States such as for example Germany, Denmark, Spain, Portugal already have integrated significant amounts of wind and solar power in the grid and are expecting more moderate growths rates in VRES capacity going forward to 2030 (see figure 2). The majority of Member States have integrated a moderate amount of wind and solar power but will experience higher growth rates of VRES compared to the group with a high VRES ratio. A minority of Member States have VRES ratios of less than 5% but are expected to have the highest growth rates going forward to 2030.

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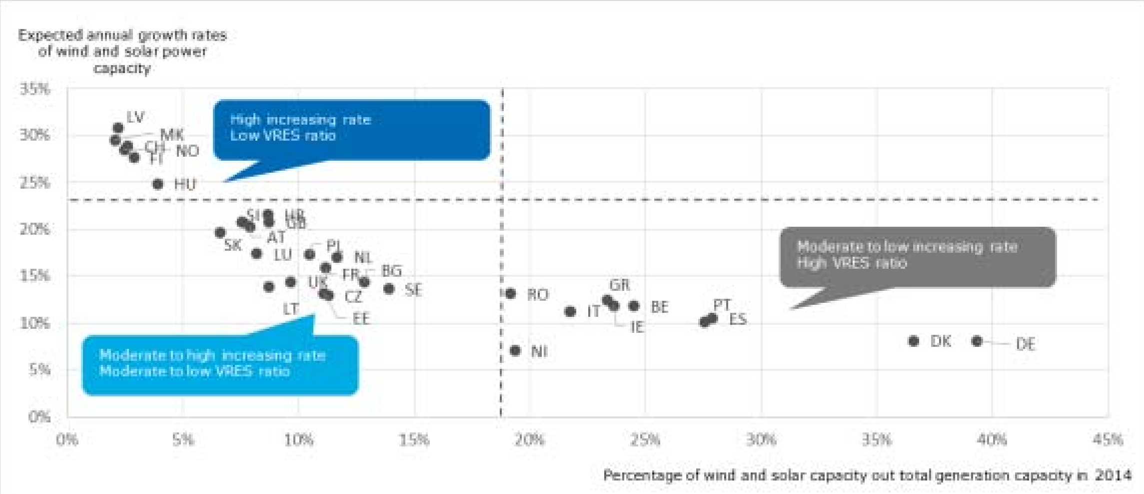
154 *"Study on tariff design for distribution systems"* (2015) AF Mercados, refE, Indra.

155 COM(2014) 15 final *"A policy framework for climate and energy in the period from 2020 to 2030"*.

156 EvolvDSO project (Deliverable 1.1) and other sources.

157 On the one hand EVs and heating/cooling loads will require more network capacity, on the other hand this kind of loads offer a huge storage potential (i.e. battery and heat storage) which can be coordinated in order to offer flexibility services to the system.

Figure 2: Wind and solar growth rates and ratio to total capacity



Source: Copenhagen Economics, VVA Europe (2016).

Distribution grids will also face an increasing challenge from the integration of new loads resulting from electric vehicles (EV) penetration and heat pumps. Currently, penetration rates for electric vehicles are low among the European countries ranging from around 700 cars in Portugal to 44,000 cars in the Netherlands (see table 1). However, the uptake of electric vehicles is expected to increase by over 50% per year going forward to 2030 in several EU Member States. Germany is expected to have the highest number of electric vehicles with over 10 million cars in 2030.

Table 1: Number of Electric Vehicles in selected countries (2014 – 2030)

Country	2014	2030 (projected)	Annual expected increase
Portugal	743	867,000	55%
Denmark	2,799	436,000	37%
Spain	3,536	4,263,000	56%
Sweden	6,990	517,000	31%
Italy	7,584	6,638,000	53%
UK	21,425	3,735,000	38%
Germany	24,419	10,024,000	46%
France	30,912	5,431,000	38%
Norway	40,887	429,000	16%
Netherlands	43,762	982,000	21%

Source: Copenhagen Economics, VVA Europe (2016).

Cost-effectively adapting to these changes will require DSOs to use flexible distributed energy resources (e.g. demand response, storage, distributed generation etc.) to manage local congestion, which will also require enhancing DSO/TSO collaboration. The use of such flexibility for the operation and planning of the network has the potential to avoid costly network expansions. For example, it may be significantly cheaper for a DSO to overcome local network congestion by occasionally procuring demand response services than to upgrade its entire network infrastructure in an area to be able to accommodate relatively uncommon demand peaks. This is a pressing issue for the EU in light of the fact that electricity network costs increased by 18.5% for households and 30% for industrial consumers between 2008 and 2012[158].

For instance, a study[159] conducted for the German distribution networks estimated that under the current conditions and depending on different scenarios, a considerable additional overall investment will be required. The study concludes that innovative planning concepts in conjunction with intelligent technologies considerably reduce the network expansion requirement[160].

In the majority of Member States presented in table 2, DSOs cannot currently procure flexibility services partially because there is a lack of a legal framework or because the services are not covered in the regulated cost base.

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158 COM(2014) 21 /2 *"Energy prices and costs in Europe"*

159 *"Moderne Verteilernetze für Deutschland(Verteilernetzstudie)"* (2014) E-Bridge, IAEW, OFFIS.

160 According to the study 90% of the capacity of installed renewable energy installations is connected up to distribution networks. With an overall coverage of 1.7 million kilometres, these networks make up about 98% of the overall national grid in Germany. An amount of 23 billion euros to 49 billion euros depending on the scenario must be invested in distribution networks by 2032 for the integration of renewable energy installations. The combination of innovative planning concepts with intelligent technologies can halve the investment requirement and reduce by 20% the average supplementary costs.

Table 2: Status Quo on DSOs incentives to procure flexibility services

Procurement of flexibility services	Number of Member States	Member state
DSOs cannot contract flexibility services	8	FI, FR, IE, IT, PT, EL, NL, ES
DSOs can contract system flexibility services for constraints management in certain situations	3	UK, BE, DE

Source: Copenhagen Economics, VVA Europe (2016).

According to EvolvDSO project[161] most DSOs surveyed (France, Ireland, Italy, Portugal) are not able to contract flexibility for congestion management although discussions on the topic take place in these countries. In Belgium and Germany, DSOs have the possibility to obtain system flexibility services via the connection and distribution access contract. These types of contracts provide for instance a reduced network fee in exchange for the control of the unit.

In Belgium, such contracts apply to new production units requesting connection at HV and MV grids. The contract allows to temporarily limit the active power of the unit via distance control. In Germany DSOs offer these "non-firm" access contracts to controllable thermal loads, i.e. heat pumps and overnight storage heating (EvolvDSO, 2016). Both countries are considering broadening these contracts to also include flexibility contracts for congestion management under normal operation state and not just emergency situations (EvolvDSO, 2016).

From data presented in the study by AF Mercados et al (2015) regarding the responsibility of DSOs in dispatching of embedded generation, use of interruptible contracts and other sources of flexibility, it is concluded that in most of Member States where DSOs can be involved in dispatching this is most of the times for coping with emergency situations (security reasons). In less than 1/3 of the Member States DSOs are using solutions such as flexibility resources or interruptible contracts in order to address grid problems.

3.2.3. *Deficiencies of current legislation*

According to the conclusions of "*Evaluation of the EU's regulatory framework for electricity market design and consumer protection in the fields of electricity and gas"* one of the main objectives of the Electricity Directive was to improve competition through better regulation, unbundling and reducing asymmetric information. In general, unbundling measures contribute to the contestability of the retail market and thus facilitate market entry by third party suppliers.

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[161] EvolvDSO ("*Development of methodologies and tools for new and evolving DSO roles for efficient DRES integration in distribution networks*") is an FP7 collaborative project funded by the European Commission (http://www.evolvdso.eu/Home/About).

The risks of less unbundling link to suboptimal switching procedures in order to deter market entry, competitive advantage which may come from the use of the same brand name or privileged access to network information, consumption data information and cross-subsidies.

On the other hand, discrimination for distribution network access appears to be less relevant than at transmission level, with a possible exception of small generation connected at distribution level. DSO unbundling is less relevant with respect to cross-border flows as flows are more local.

CEER finds that in general the implementation of unbundling rules has been satisfactory[162]. Regarding the implementation of the measures, CEER is reporting problems in the implementation of the provisions related to branding and communication. The Commission has taken action towards the proper implementation of the relevant provisions through compliance checks and infringement procedures, requesting Member States to ensure a clear separation of identity of the supply and distribution activities within a vertically integrated undertaking.

Some of the factors that may influence and raise the impact of the foreseen risks are the increased penetration of RES E generation at distribution level and introduction of smart metering systems.

In terms of **effectiveness**, the intervention mainly aimed at the unbundling of vertical integrated distribution companies with the objective to ensure non-discriminatory and transparent third party access in distribution networks, in order to promote competition in the energy market. There is no evidence that the intervention within the boundaries of the unbundling requirements, did not achieve the objective of promoting competition in the market.

The Electricity Directive leaves it at the discretion of Member States to decide which level of unbundling will apply for small DSOs (less than 100,000 customers) and the detailed tasks that DSOs should carry out at a national level. There is a quite diverse situation across EU Member States when it comes to responsibilities of DSOs across the EU.

Provisions which aimed to enhance the DSOs position in using demand side management and energy efficiency measures in planning their networks did not prove to be effective. Only in few Member States, DSOs are in position to use such tools in order to avoid costly investments and operate their networks more efficiently.

In terms of **relevance**, the original objectives of DSO unbundling requirements and the framework in which Member States can decide on the responsibilities of operators still correspond to the EU objective of a competitive internal energy market. The implementation of smart metering systems (wide scale roll-out in 17 Member States) will generate more granular consumption data and new business opportunities in the retail market. Moreover, the introduction of more RES E generation at distribution level will require a more active management of the network from DSOs. Even if the measures under the Electricity Directive had included to a certain extent these developments the

162 *"Status Review on the Implementation of Distribution System Operators' Unbundling Provisions of the 3rd Energy Package"* (2016) CEER.

focus of the intervention was not on these new needs that are estimated to grow with the completion of smart metering systems and the installation of distributed RES E.

In terms of **coherence**, the measures are fully coherent with the objectives of the internal energy market. Unbundling provisions for DSOs complement the relevant requirements for TSOs, by providing a transparent and non-discriminatory framework for third party access also at retail market level. These provisions are fundamental for the promotion of competition in the energy market, the entrance of new energy service providers and the development of new services.

In terms of **EU-added value**, the requirements on unbundling are fundamental for the promotion of competition in the internal energy market. Provisions which are relevant to DSOs have the characteristic of a permanent effect.

Gap analysis

According to the conclusions of the *"Evaluation of the EU's regulatory framework for electricity market design and consumer protection in the fields of electricity and gas"* with the deployment of smart metering systems across EU Member States a large amount of data will be available to DSOs. This development requires a closer assessment and consideration of specific measures.

In terms of DSO responsibilities, it is clear that there is a wide variety of roles and tasks for DSOs across the EU. This situation does not allow for the application of a uniform set of responsibilities for all DSOs, as such measure would have a disproportionate effect on DSOs across the EU, based mostly on the variety of distribution voltage levels and number of connected customers.

It seems however appropriate to enhance the role of DSOs when it comes to additional tools such as the use of flexible resources in order to improve their efficiency in terms of costs and quality of service provided to system users. Such measures however could only be introduced with the parallel introduction of suitable provisions which prohibit DSOs to take advantage of their monopolistic position in the market by clarifying their role in specific activities. In the absence of such measures, the DSOs could foreclose the market and reduce the benefits for the system users, leading to an inefficient allocation of resources and reduction of social welfare.

3.2.4. *Presentation of the options*

Distribution system operators

Under **Option 0** (BAU) existing provisions of the Electricity Directive will continue to apply concerning the tasks of DSOs. In this case Member States are responsible for deciding on a number of non-core tasks as well as on remuneration of DSOs.

Option 0+ (Non-regulatory approach) was discarded as the existing EU legislative framework does not directly address flexibility in distribution networks. This needs to be further codified in law in order to ensure, *inter alia*, a level playing field for the achievement of the EU's RES E deployment objectives given new market conditions. In addition, it is unlikely that voluntary cooperation between Member States would deliver the desirable policy objectives in this case.

Under **Option 1** the objective is to allow the DSOs to procure and use flexibility services. Introduce specific conditions under which DSOs should procure flexibility in order to ensure neutrality and enable longer term investments in flexibility. Moreover, the role of DSOs regarding specific tasks such as data management, ownership and operation of storage and electric vehicle charging infrastructure will be clarified under this option. Measures under Option 1 will also seek to establish an enhanced cooperation between TSOs and DSOs in terms of network operation and planning.

Under **Option 2** measures will aim to define specific tasks that DSOs across the EU should be allowed and not allowed to carry out. The tasks that DSOs should be allowed to carry out would include their core tasks and tasks where there is no potential competition, while activities which are open to competition or already forbidden (e.g. generation or supply) should not be allowed. Also, under this option existing unbundling rules will apply also to DSOs with less than 100,000 customers (small DSOs), abolishing the provision of the Electricity Directive which allows Member States to exempt small DSOs from legal and functional unbundling.

3.2.5. *Comparison of the options*

a. The extent to which they would achieve the objectives (effectiveness)

The main objective is to enable DSOs to locally manage challenges of the energy transition in a cost-efficient and sustainable way, without distorting the market.

In general the current EU framework leaves to Member States the more detailed identification of the distribution framework at national level in terms of the specific tasks that DSOs should carry out and the tools available for operating and developing their grids. However, in light of the major changes the electricity system is undergoing, **Option 0** is likely to be inadequate in ensuring a cost efficient grid operation.

DSOs may in some countries not have access to appropriate tools in order to operate efficiently, for instance by procuring flexibility from their customers through aggregators or local markets, while in many countries they are not adequately incentivised through the remuneration schemes in place to do so. The Electricity Directive requires DSOs to take into account demand-side management and energy efficiency measures or distributed generation as well as conventional assets expansion when planning their networks. However, it is up to Member States (national authorities, NRAs and DSOs) to ensure that this is carried out. While this option provides an open EU framework for Member States, it is also likely to lead to national specific frameworks which are not conducive to the use of demand side flexibility at DSO level.

Moreover, there are different approaches across Member States for the use of demand side flexibility from DSOs and a lack of market rules under which DSOs shall procure flexibility services, while there is no clear framework regarding the involvement of DSOs in activities such as storage or electric vehicle charging infrastructure.

The measures under **Option 1** will establish a clear legal basis for allowing DSOs to use flexibility. Specific measures under this option will also clarify the role of DSOs in competitive activities such as storage and electric vehicles charging, and set a specific framework for DSO involvement. Such a regulatory framework should allow different solutions in order to address specific needs of the network, based on market procedures (e.g. long-term contracting of flexibility services such as large scale storage). Regarding the involvement of DSOs in data handling, specific measures under Option 1 will ensure neutrality of operators (see also Annexe 7.3 of the present annexes to the impact assessment).

DSOs should harness flexibility from grid users without the risk of distorting or hampering the development under competitive terms of distributed energy services, such as demand response, storage, supply and generation, through discriminatory practices or monopolistic behaviour. This Option will reduce the risk of competition distortions compared to Option 0. By defining a common framework on how DSOs can procure flexibility and perform specific roles such as involvement in storage, a level playing field of a certain standard will be ensured across Member States, unlike the situation where Member States adopt different approaches to this issue. Moreover, cooperation with TSOs is important as resources which provide flexibility to the system are located in the distribution system and therefore coordinated operation and exchange of information between operators will be required.

Effectiveness of this option can be limited by the fact that the differences among distribution system structures and tasks of DSOs across the EU, will possibly require that measures at EU level have to remain broad enough in order to accommodate diverse situations.

Regarding the use of flexibility, the effectiveness of this option also depends on the implementation in each Member State, as national remuneration schemes are important in order to provide to DSOs the right incentives to use flexibility and be properly remunerated (links to options under distribution tariffs and remuneration, see also Annexe 3.3 of the present annexes to the impact assessment).

Option 2 foresees a uniform framework for DSOs in terms of tasks and level of unbundling across the EU. The procurement of flexibility from DSOs will be similar to Option 1.

Stricter unbundling rules for small DSOs may lower the risk for discriminatory behaviour and result in gains in retail competition. On the other hand, given that DSOs are natural monopolies, such measures will not fully guarantee the avoidance of the dominant role of DSOs in procuring flexibility from system users. Therefore, additional measures will be needed in order to avoid monopolistic behaviour from DSOs which could lead to market distortions.

The definition of a uniform set of tasks applicable to all DSOs could lead to non-effective arrangements depending on the different market conditions as such a framework would not be able to account for the differences between distribution systems across the EU (e.g. different retail market conditions or structural and technical differences of distribution systems)[163].

b. Their respective key economic impacts and benefit/cost ratio, cost-effectiveness (efficiency) & Economic impacts

[163] CEER in its public consultation paper "*The future role of DSOs*" (2014), proposes a set of potential DSO activities categorized under three broad areas (core activities, 'grey area' activities and forbidden activities). In its conclusion paper (2015), CEER remarks that there is no single model for what a DSO can and cannot do, but rather a number of grey areas where DSOs can participate under certain conditions.

Impacts of measures under **Option 1** will be highly dependent on the detailed implementation at national level, as for instance the extent to which DSOs under the monitoring of the NRA will decide to supplant grid expansions with the use of flexibility in network planning. The decision of such measures will be made on the basis of the most beneficial solution for each distribution system taking into account avoided investments and considering the costs of employing flexible resources.

Curtailment of RES E in grid planning as quantified in the E-Bridge et al (2014) study[164] could help reducing the grid expansion requirements caused by new RES E installations in the future by at least 22% in the higher voltage grid (>110 kV). Those savings of 22% can be achieved when allowing for 3% curtailment in grid planning. Considered generation for curtailment are wind and solar power installations larger than 7 kW; that affects 52% of all installations, whose aggregated capacity accounts for more than 90% of the total capacity installed. The benefits of curtailment are lower expansion requirements for the grids, which do not have to be built to accommodate flows corresponding to the maximum capacity of the connected RES E installations.

Copenhagen Economics, VVA Europe (2016)[165] estimate that the total savings at EU level from avoided distribution grid investments will be in the order of at least EUR 3.5 to 5 billion in yearly investments towards 2030 (table 3). This corresponds to a total of approximately EUR 50-85 billion accumulated from 2016. In practice, the potential savings could be significantly higher, to the extent which supply and demand side flexibility measures can be used in combination rather than each measure in isolation.

Table 3: Avoided grid investments from flexibility

Extra grid investment from increased DG and load growth (EUR billion) yearly at EU level	11
Savings from demand flexibility alone (percent)	30 - 55
Savings from supply flexibility alone (percent)	44 - 55
Savings from combination of demand and supply flexibility (percentage)	At least 30-44
Very conservative estimate of avoided extra grid investments from flexibility yearly at EU level (EUR billion)	**3.5 to 5**

Source: Copenhagen Economics, VVA Europe (2016).

McKinsey & Company (2015)[166] found that energy storage can absorb a large share of the power that would otherwise been curtailed even in a scenario with high share of variable renewable power, and most of the flexibility would be located on the distribution grid level. Decisions on which source of flexibility is more efficient should be made on the basis of the specific needs of the network according to transparent, non-discriminatory and market-based procedures, under close regulatory control.

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[164] *"Moderne Verteilernetze für Deutschland (Verteilernetzstudie)"* (2014) E-Bridge, IAEW, OFFIS.

[165] *"Impact assessment support study on: Policies for DSOs, Distribution Tariffs and Data Handling"* (2016) Copenhagen Economics, VVA Europe..

[166] "*Commercialisation of energy storage in Europe"* (2015) McKinsey & Company.

Related measures are expected to create net benefits for the electricity system as they will lower distribution costs. Moreover, the use of flexibility from distribution system operators will stimulate the introduction of new services and the market entrance of new players such as aggregators. Consumers will benefit from lower network tariffs (reflecting lower distribution costs) and directly by participating in demand response programmes or other services to the DSO.

The clarification of the EU framework regarding the role of DSOs in specific tasks such as data handling, storage and electric vehicle charging, is expected to have positive net benefits for the electricity system and positive economic societal net benefits. The main reason is that these tasks can be carried out more efficiently by market players rather than natural monopolies. Measures under this option will allow certain exemptions in cases where a market is new (e.g. electric vehicles) or where there is no interest from market parties to invest in such activities.

Option 2 would result in higher costs as small DSOs (serving less than 100,000 customers) would have to implement legal unbundling criteria. Such an option would lead small DSOs to separate distribution from the supply activity of the VIU and possibly merge with larger DSOs, resulting in one-off and structural costs which differ per Member State. On the other hand, main benefits would result from more transparent third party access which could potentially have positive impacts on competition. Such costs and benefits are hard to be fully quantified as many parameters and different local conditions should be taken into account.

c. Simplification and/or administrative impact for companies and consumers

Option 2 for distribution system operators is expected to have high administrative costs on the concerned energy companies because of the unbundling requirement on small DSOs (less than 100,000 customers) which is expected to require a restructuring of those energy companies affected by the measures.

d. Impacts on public administrations

Impacts on public administration are summarized in Section 7 below.

e. Trade-offs and synergies associated with each option with other foreseen measures

Option 1 for distribution system operators demonstrates multiple synergies with options under demand response and smart metering. Demand response programmes through aggregators can provide services to DSOs who wish to use flexibility in network operation and planning.

f. Likely uncertainty in the key findings and conclusions

There is a medium risk associated with the uncertainty of the assessment of costs and benefits of the presented options. However, it is considered that this risk cannot influence the decision on the preferred option as there is a high differentiation among the presented options in terms of qualitative and quantitative characteristics.

g. Which Option is preferred and why

Option 1 is the preferred option as it demonstrates the higher potential net benefits for electricity system and society and expected to demonstrate additional benefits compared to Option 0 without resulting in excessive costs for the involved parties. Consumers will benefit from lower distribution costs and improved competition in the market.

3.2.6. *Subsidiarity*

EU has a shared competence with Member States in the field of energy pursuant to Article 4(1) TFEU. In line with Article 194 of the TFEU, the EU is competent to establish measures to ensure the functioning of the energy market, ensure security of supply and promote energy efficiency.

Under the energy transition, distribution grids will have to integrate even higher amounts of RES E generation, while new technologies and new consumption loads will be connected to the distribution grid. Distributed generation has the potential directly or through aggregation to participate in national and cross-border energy markets. Moreover, other distributed resources such as demand response or energy storage can participate in various markets and provide ancillary services to the system also with a cross-border aspect.

Moreover, DSOs should have the ability to integrate new generation and consumption loads under cost-efficient terms. The access conditions for RES E generation and other distributed resources shall be transparent and the DSO's role should be neutral in order to create a level playing field for these resources. As the amount of resources such as RES E generation, but in the future also other resources such as storage, will increase, the conditions under which these resources can access the grid and participate in the national and cross-border energy markets is expected to become more relevant.

The neutrality of DSOs when they are using flexibility to manage local congestion is a precondition for well-functioning retail market. While electricity distribution can be considered a local business, harmonised rules ensuring neutrality of DSOs towards other market actors including new energy services providers create a level playing field for RES E development across the EU, crucial in achieving the RES E targets, and support the completion of internal energy market.

Distribution grid issues may affect the development of the internal energy market and raise concerns over possible discrimination among system users from different Member States who however have access in the same energy markets. Uncoordinated, fragmented national policies at distribution level may have indirect negative effects on neighbouring Member States, and distort the internal market. EU action therefore has significant added value by ensuring a coherent approach in all Member States.

3.2.7. *Stakeholders' opinions*

3.2.7.1. *Results of the consultation on the new Energy Market Design*

According to the results of the public consultation on a new Energy Market Design[167] the respondents view active distribution system operation, neutral market facilitation and

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[167] https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

data hub management as possible functions for DSOs. Some stakeholders pointed to a potential conflict of interests for DSOs in their new role in case they are also active in the supply business and emphasized that the neutrality of DSOs should be ensured. A large number of the stakeholders stressed the importance of data protection and privacy, and consumer's ownership of data. Furthermore, a high number of respondents stressed the need of specific rules regarding access to data.

Governance rules for DSOs and Models of data handling

Question: *"How should governance rules for distribution system operators and access to metering data be adapted (data handling and ensuring data privacy etc.) in light of market and technological developments? Are additional provisions on management of and access by the relevant parties (end-customers, distribution system operators, transmission system operators, suppliers, third party service providers and regulators) to the metering data required?"*

Summary of findings:

Regulators stress the importance of neutrality in the role of the DSOs as market facilitators. To achieve this will require to:

- Set out exactly what a neutral market facilitator entails;
- When a DSO should be involved in an activity and when it should not;
- NRAs to provide careful governance, with a focus on driving a convergent approach across Europe.

Regulators consider that consumers must be guaranteed the ownership and control of their data. The DSOs, or other data handlers, must ensure the protection of consumers' data.

IFIEC considers that DSOs should not play the role of market facilitator, the involvement of a third party is perceived to better support neutrality and a level playing field. Moreover, coordination of TSOs and DSOs and potentially extended role of DSOs with respect to congestion management, forecasting, balancing, etc. would require a separate regulatory framework. However, IFIEC express concerns that some smaller DSOs might be overstrained by this. Extended roles for DSO should be in the interest of consumers and only be implemented when it is economically efficient.

EUROCHAMBERS believes that due to different regional and local conditions a one size fits all approach for governance rules for distribution system operators is not appropriate. The EU could support Member States by developing guidelines (e.g. on grid infrastructures and incentive systems).

Most energy industry stakeholders (CEDEC, EDSO, ESMIG, ETP, EUROBAT, EWEA, GEODE) believe that the role of DSOs should focus on active grid management and neutral market facilitation. Some respondents state that the current regulatory framework prevents DSOs from taking on some roles, such as procurer of system flexibility services and to procure balancing services from third parties, and such barriers should be eliminated.

Also SEDC envisages that DSOs should be neutral market facilitators where unbundling is fully implemented. However, in this scenario DSOs should not be active in markets such as for demand response, as this would undermine their neutrality.

3.2.7.2. *Public consultation on the Retail Energy Market*

According to the results of the 2014 public consultation on the Retail Energy Market[168] the majority of the respondents consider that DSOs should carry out tasks such as data management, balancing of the local grid, including distributed generation and demand response, and connection of new generation/capacity (e.g. solar panels).

According to the majority of the stakeholders these activities should be carried out under good regulatory oversight, with sufficient independence from supply activities, while a clear definition of the role of DSOs (and TSOs), but also of the relationship with suppliers and consumers, is required.

3.2.7.3. *Electricity Regulatory Forum - European Parliament*

Relevant conclusions of the 31st EU Electricity Regulatory Forum:

- *"The Forum stresses the importance of innovative solutions and active system management in distribution systems in order to avoid costly investments and raise efficiencies in system operation. It highlights the need for DSOs to be able to purchase flexibility services for operation of their systems whilst remaining neutral market facilitators, as well as the need to further consider the design of distribution network tariffs to provide appropriate incentives. The Forum encourages regulators, TSOs and DSOs to work together towards the development of such solutions as well as to share best practices."*

[168] https://ec.europa.eu/energy/en/consultations/consultation-retail-energy-market

3.3. Distribution network tariffs and DSO remuneration

3.3.1. *Summary table*

a. Table 1: Remuneration of DSOs

Objective: A performance-based remuneration framework which incentivize DSOs to increase efficiencies in planning and innovative operation of their networks.		
Option: 0	**Option 1**	**Option 2**
BAU Member States (NRAs) are mainly responsible on deciding on the detailed framework for the remuneration of DSOs.	- Put in place key EU-wide principles and guidance regarding the remuneration of DSOs, including flexibility services in the cost-base and incentivising efficient operation and planning of grids. - Require DSO to prepare and implement multi-annual development plans, and coordinate with TSOs on such multi-annual development plans. - Require NRAs to periodically publish a set of common EU performance indicators that enable the comparison of DSOs performance and the fairness of distribution tariffs.	Fully harmonize remuneration methodologies for all DSOs at EU level.
Pro Current framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro Performance based remuneration will incentivise DSOs to become more cost-efficient and offer better quality services. It would support integration of RES E and EU targets.	Pro A harmonized methodology would guarantee the implementation of specific principles.
Con Current EU framework provides only some general principles, and not specific guidance towards regulatory schemes which incentivize DSOs and raise efficiencies.	Con Detailed implementation will still have to be realized at Member State level, which may reduce effectiveness of measures in some cases.	Con A complete harmonisation of DSO remuneration schemes would not meet the specificities of different distribution systems. Therefore, such an option would possibly have disproportionate effects while not meeting the subsidiarity principle.
Most suitable option(s): Option 1 is the preferred option as it will reinforce the existing framework by providing guidance on effective remuneration schemes and enhancing transparency requirements		

b. Table 2: Distribution network tariffs

Objective: Distribution tariffs that send accurate price signals to grid users and aim to fair allocation of distribution network costs.		
Option: O	**Option 1**	**Option 2**
BAU Member States (NRAs) are mainly responsible for deciding on the detailed distribution tariffs.	- Impose on NRAs more detailed transparency and comparability requirements for distribution tariffs methodologies. - Put in place EU-wide principles and guidance which ensure fair, dynamic, time-dependent distribution tariffs in order to facilitate the integration of distributed energy resources and self-consumption.	Harmonization of distribution tariffs across the EU; fully harmonize distribution tariff structures at EU level for all EU DSOs, through concrete requirements for NRAs on tariff setting.
Pro Current framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro Principles regarding network tariffs will increase efficient use of the system and ensure a fairer allocation of network costs.	Pro A harmonized methodology would guarantee the implementation of specific principles.
Con Current EU framework provides only some general principles, and not specific guidance towards distribution network tariffs which effectively allocate costs and accommodate EU policies.	Con Detailed implementation will still have to be realized at Member State level, which may reduce effectiveness of measures in some cases.	Con A complete harmonisation of DSO structures would not meet the specificities of different distribution systems. Therefore, such an option would possibly have disproportionate effects while not meeting the subsidiarity principle.
Most suitable option(s): Option 1 is the preferred option as it will reinforce the existing framework by providing guidance on effective distribution network tariffs and enhancing transparency requirements		

3.3.2. *Description of the baseline*

Legal framework

According to Article 37(1) of the Electricity Directive, National Regulatory Authorities (NRAs) are responsible for setting or approving distribution tariffs or their methodologies.

Article 37(6) and Article 37(8) of the Electricity Directive set some more specific requirements for NRAs on tariff setting procedures and provide general principles. These principles require tariffs or methodologies to allow the necessary investments in the networks and ensure viability of the networks. NRAs shall also ensure that operators are granted appropriate short and long-term incentives to increase efficiencies, foster market integration and security of supply and support the related research activities.

Assessment of current situation

According to available data[169] allowed revenues (remuneration) for DSOs are set or approved by regulators in the majority of Member States, with the exception of Spain (ES), where allowed revenues are set by the Government.

In most Member States tariffs are also being set by the national regulator. However in some countries the responsibilities are shared between the regulator and the DSO, the regulator mainly defines the rules and approves the tariffs proposed by the DSO. Spain is the only country where the Government sets the tariffs. Distribution tariffs are published in all Member States. However, in Spain distribution tariffs are bundled with other tariff components, covering costs such as renewable generation fees.

There is a wide variety of remuneration schemes and tariff structures across the EU, which partly reflects the different situations and local conditions in Member States. With the exception of the UK, current incentive-based regulatory schemes place little emphasis on the output delivered by the distributor, but for quality of service schemes. Moreover, the following conclusions can be derived from the assessment of the current regulatory regimes across the EU:

- Typically DSOs are not exposed to volume risk and to the risk that their investment turns out to be less useful than expected when they were decided, for example because of lower than expected demand.
- Revenue setting mechanisms based on benchmarking are implemented in countries where the distribution sector is highly fragmented.
- Regulators and stakeholders are generally less involved in the decision-making process on distribution network development, as compared to transmission.
- Traditional tariff structures reflect a situation of limited availability of information on each consumer's responsibility in causing distribution costs and are also affected by affordability and fairness considerations.

[169] "*Study on tariff design for distribution systems*" (2015) AF Mercados, refE, Indra..

- In most countries, the share of distribution revenues from tariff components based on energy is large, resulting in an asymmetry between the structure of distribution costs (mostly fixed) and the way they are charged to consumers.
- In the electricity sector the energy tariff component applied to households represent on average 69% of the total network charge. This practice is common in most countries apart from three (The Netherlands, Spain and Sweden) where the energy charge weights between 21% and 0%.
- In the case of industrial customers the weight of the energy component is still dominant (around 60% for both small and large industrial clients) but there is more variability among countries and the corresponding weight ranges between 13% and 100%.

The current distribution tariff structures have been inherited from previous regulatory regimes, when tariff structures were a simple combination of distribution and supply costs, including fixed and variable energy costs, for services provided by a single utility. The distribution tariff is generally based on the distributed amount of energy, occasionally in a way that varies across times of the day and across seasons, but only rarely linked to peak load requirements. Historically, this type of volume based pricing structure was appropriate, as consumers with high peak load requirements also tended to be those who consumed most energy. Going forward the total costs on the system, which are correlated with the size of peak demand, will be less linked to total energy consumption.

Currently, the majority of DSO revenue is collected through volumetric tariffs, i.e. 69% of the revenue for household consumers, 54% for small industrial consumers and 58% for large industrial consumers (table 3). This also shows that most EU Member States have a two-part tariff with a capacity and/or fixed component and a volumetric element.

Table 3: Status quo on volumetric and capacity tariffs among Member States

Tariff structure elements	Tariff component for household consumers	Tariff component for small industrial consumers	Tariff component for large industrial consumers
Member states where the volumetric element weights over 50% of the DSO tariff	AT, CY, CZ, FR, DE, GR, HU, IT, LU, PL, PT, RO, SK, SI, GB	CY, CZ, FI, FR, DE, GR, HU, RO, SE, SK, GB	AT, CY, FI, FR, GR, HU, PL, RO, SE, SK, SI, NL, GB
Member states where the capacity element + fixed charge weights over 50% of the DSO tariff	ES, SE, NL	AT, IT, LU, PL, PT, SI, ES, NL	CZ, DE, IT, LU, PT, ES
EU capacity element + fixed component average	31%	46%	42%
EU volumetric element average	69%	54%	58%

Note: Bulgaria and Latvia are not included in the survey, Netherlands has a 100% capacity based tariff for households and small industrial consumers as the only country in the EU. In DK, Finland, Luxembourg and Malta time-of-use tariffs are not available for household customers.

Source: Copenhagen Economics, VVA Europe (2016) based on Mercados (2015) and Eurelectric (2013).

Only 3 Member States (Spain, Sweden and the Netherlands) have a capacity and/or fixed component that weighs over 50% of distribution tariff for household consumers. The Netherlands have a 100% capacity based tariff for households and small industrial consumers as the only country in the EU, while Romania has a 100% volumetric tariff. Between 6 and 8 Member States apply distribution tariffs where the capacity and fixed tariff weighs over 50% of the tariff for small and industrial consumers.

In 17 countries a time-of-use distribution tariff is applied, typically for non-residential consumers and with daily (night/day) or seasonal (winter/summer) structure (Mercados 2015). France has implemented tariffs that can incite demand response by introducing critical peak pricing. The critical peak pricing is for consumers with a three-phase connection where up to 21 days a year could be selected with a 24 hours' notice signal.

Table 4: Status quo on time-of-use tariffs in Member States

Tariff elements	Number of Member States	Member State
Time-of-use tariffs	17	AT, HR, CZ, DK, FI, FR, EE, GR, IR, LU, LT, MT, PL, PT, SI, ES, UK
Critical peak pricing	1	FR
“Social tariff element” to cross-subsidize low income consumer	5	ES, IT, FR, GR, PT

Source: Copenhagen Economics, VVA Europe (2016) based on Mercados (2015) and Eurelectric (2013).

Regarding charges applied to distributed generation there is a split picture among Member States for which data were available. In 8 Member States, distributed generation is subject to use of system charges while in 6 Member States no charges are applied. There is also a diverse situation regarding the connection charges that distributed generators have to pay with a wide variety of charging principles (i.e. shallow, deep, semi-deep or semi-shallow).

Table 5: Connection charges and use of system charges for distributed generation in Member States

Member State	Connection Charge	Use of system charge
Austria	Deep	No
Belgium	Shallow	Yes
Bulgaria	Deep	N/A
Croatia	N/A	N/A
Cyprus	N/A	N/A
Czech Republic	Deep	N/A
Denmark	Shallow	Yes
Estonia	Deep	N/A
Finland	N/A	Yes
France	Semi-deep	No
Germany	Shallow	No
Greece	Shallow	N/A
Hungary	Semi-shallow	N/A
Ireland	Shallow	No
Italy	Shallow	Yes
Latvia	Deep	N/A
Lithuania	Semi-shallow	N/A
Luxembourg	N/A	Yes
Malta	N/A	N/A
Netherlands	Shallow	Yes
Norway	Shallow	N/A
Poland	Shallow	N/A
Portugal	Deep	No
Romania	Semi-deep	N/A
Slovakia	Deep	N/A
Slovenia	Shallow	N/A
Spain	Deep	No
Sweden	Semi-deep	Yes
UK	Semi-shallow	Yes

Source: THINK report "From distribution networks to Smart distribution systems" (2013).

The above data demonstrate a wide variety of distribution tariff structures for consumption or generation across EU Member States. This wide variety of tariffs can be attributed to a certain extent to the different local conditions and costs structures in each country; however, distribution tariffs do not always follow specific principles or they introduce different diverse conditions for investments for EU consumers who wish to invest in new technologies including self-generation.

It is widely accepted[170] that the developments which are taking place in the distribution systems such as the integration of vast amounts of variable RES E generation or the integration of new loads (e.g. heat pumps, electric vehicles), require distribution tariffs which provide the right economic signals for the use and development of the system, allocate costs in a fair way amongst system users and provide stability for investments for DSOs and connected infrastructure.

Regarding remuneration schemes, DSOs across EU are not always encouraged through appropriate regulatory frameworks to choose the most cost-efficient investments and innovative network solutions. In many EU Member States the current regulation of DSOs does not always provide the right incentives to efficiently develop and operate the grid, and to consider new flexible resources in network planning made possible by distributed energy resources[171].

Moreover, different approaches are applied on how regulatory frameworks stimulate DSOs to deploy innovative technologies. According to Eurelectric [172] in the majority of Member States analysed (13 out of 20), the regulatory framework is either neutral or hampers innovation and R&D[173] in distribution systems.

3.3.3. *Deficiencies of the current legislation*

The Electricity Directive provides an open framework for NRAs in Member States for setting distribution network tariffs. The current legislation already provides some principles on the elements that national regulators should consider when deciding on the remuneration methodology, the allocation of costs on different system users, tariff structure etc.

In terms of governance this framework shall continue to exist, as tariff setting is one of the expertise areas and core tasks of NRAs. However, in the context of the rapid transformation of the energy system, new generation technologies and new consumption loads will alter the traditional flows of energy in the system and impact the operation of distribution and transmission grids. Distribution tariff structures will have to induce an efficient use of the system, while remuneration schemes have to incentivise DSOs for efficient operation and planning of their networks. This will require further steps to be taken in EU legislation in order to create a common basis for the development of a competitive and open retail market and support the effective integration of RES E generation and new technologies under equal and fair terms across Member States.

[170] See for instance the CEER conclusions paper on "*The future role for DSOs*" (2015) and the THINK report *"From distribution networks to smart distribution systems: Rethinking the regulation of European Electricity DSOs"* (2013).

[171] *"From distribution networks to smart distribution systems: Rethinking the regulation of European Electricity DSOs*" (2013) THINK.

[172] *"Innovation incentives for DSOs – a must in the new energy market development"* (2016) EURELECTRIC.

[173] 'Research, innovation and competitiveness' has been identified as one of the five dimensions of the Energy Union strategy (COM(2015) 80 final). In this context, smart grids and smart home technology are listed in the core priorities in order promote growth and jobs through the energy sector and to create benefits for the energy consumer.

CEER[174] and ACER[175] recognise that the current regulatory frameworks applied in many Member States may not fully address the new challenges such as the complex electricity flows caused by small scale generation. Addressing this kind of challenges through the regulatory framework would require the remuneration of innovative investments and the introduction of the right incentives for flexible solutions which can contribute in solving short-term and long-term congestions in the distribution grids[176].

While NRAs have enough flexibility in setting distribution tariff structures which best fit to their local conditions, often there is a lack of important principles which would lead to a fair allocation of distribution costs amongst system users or the avoidance of implicit subsidies amongst system users. Moreover, the right long-term economic signals to system users which would allow for a more rational development of the network are often not in place.

The diversity of tariff structures is also creating different conditions for system users such as RES E generators who directly or indirectly through aggregation can participate in the energy market. Different regulatory frameworks regarding the access conditions including distribution tariffs of a variety of energy resources which participate in national and cross-border energy markets could potentially distort competition in the internal energy market and negatively affect the level of investment in RES E and new technologies.

Therefore, a further clarification of the overarching principles might be necessary accompanied by measures which ensure the transparency of methodologies used and the underlying costs. In this context, issues such as fees and tariffs that distributed energy resources such as storage facilities have to pay would also need to be clarified.

A more detailed guidance to Member States should be decided on the basis of enhancing further the effectiveness of the distribution network tariff schemes across the EU in order to incentivise DSOs to raise efficiencies in their networks and to ensure a level playing field for all system users connected to distribution networks.

3.3.4. *Presentation of the options*

Distribution tariffs and remuneration of DSOs (tables 1 and 2 in Section 1)

Under **Option 0** (BAU) distribution tariffs and remuneration for DSOs will continue to be set according to the current framework and principles set in the Electricity Directive. Regulatory authorities set or approve distribution tariffs or methodologies in the framework of the Third Package.

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[174] *"The future role for DSOs"* (2015) CEER.

[175] *"A Bridge to 2025 Conclusions Paper"* (2014) ACER.

[176] The need for incentivising grid operators to enable and use flexibility, but also to improve distribution tariffs in order to incentivise an efficient consumer response, was widely recognised amongst the members of the Expert Group 3 (EG3) of the Smart Grids Task Force. The full analysis in included in the 2015 report *"Regulatory Recommendations for the Deployment of Flexibility"* (https://ec.europa.eu/energy/sites/ener/files/documents/EG3%20Final%20-%20January%202015.pdf).

A stronger enforcement and/or voluntary cooperation (Option 0+) has not been considered as the existing framework does not provide the necessary policy tools and principles for providing further guidance to Member States, while voluntary cooperation between Member States could only be used for sharing best-practices.

Under **Option 1** in addition to the existing framework, measures on key EU-wide principles and guidance regarding the remuneration of DSOs, including flexibility services (e.g. energy storage and demand response) in the cost-base and incentivising efficient operation and planning of grids will be put in place. EU-wide principles will also ensure fair, dynamic, time-dependent distribution tariffs in order to facilitate the integration of distributed energy resources including storage facilities and self-consumption. Such principles could be further detailed in an implementing act providing clear guidance to Member States.

Moreover, DSOs will have to prepare and implement multi-annual development plans, and coordinate with TSOs on such multi-annual development plans.

NRAs in addition to their existing competences will have to periodically publish a set of common EU performance indicators that enable the comparison of DSOs performance and the fairness of distribution tariffs. NRAs will also have to implement more detailed transparency and comparability requirements for distribution tariffs methodologies.

Measures under **Option 2** will aim to fully harmonize remuneration methodologies for all DSOs at EU level, as well as distribution tariffs (e.g. structures and methodologies). Full harmonization of tariff structures could include the definition of specific tariff elements (capacity or energy component, fixed charge etc.), but also specific rules on the allocation of distribution costs to the different tariff elements.

3.3.5. <u>*Comparison of the options*</u>

a. The extent to which they would achieve the objectives (effectiveness)

Distribution network tariffs and remuneration of DSOs (tables 1 and 2 in Section 1)

The main objective is to achieve distribution tariffs that send accurate price signals to grid users and aim at a fair allocation of distribution network costs. Regarding remuneration of DSOs the aim is incentivize DSOs to increase efficiencies in planning and innovative operation of their networks.

Under **Option 0** Member States (NRAs) will continue to set tariffs and remuneration methodologies according to the framework provided in the Electricity Directive. However, the current tariff structures and methodologies do not always fulfil the desirable results under the main objective. The current tariff structure in most Member States does not sufficiently achieve the economic purpose of network tariffs. For instance tariffs do not always reflect the costs of the grid from a particular type of behaviour, such as additional consumption during peak load, or in other instances from beneficial behaviour, such as charging a storage or electric vehicle to absorb a peak in variable renewable generation. In several Member States different generation resources face different tariffs, and therefore create an uneven playing field between resources or between markets (national or cross-border).

Additionally, Member States are not obliged to provide clear transparency requirements regarding the costs and methodologies for network tariffs. This creates an information asymmetry between various players in the market and the risk of not having a clear and predictable framework.

Therefore, under this option the development of more advanced and transparent distribution tariff frameworks is left to Member States, facing the risk that some Member States will not develop the appropriate regulatory framework without clear guidance. Moreover, it may also lead to various rules and solutions, which risk not dealing with the issues of cost reflective use of the grid, or transparent regulatory framework and appropriate incentives for operators.

Measures under **Option 1** aim to enhance the principles of the Electricity Directive for setting network tariffs in order to provide a clearer guidance to Member States in achieving the policy objectives. These principles will set a framework for fair, dynamic and time-dependent tariffs which fairly reflect costs and facilitate the integration of distributed energy resources.

This option could be more effective if in addition to measures to be included in the Directive, more specific guidance will be provided to Member States through implementing legislation. A more detailed guidance would set the framework under which NRAs can establish fair and cost reflective tariffs and incentivise DSOs to raise efficiencies in their networks.

Specific transparency requirements are expected to effectively enhance the level of transparency regarding the underlying costs in tariff setting and the detailed methodologies.

A full harmonization of distribution tariffs structures and methodologies under **Option 2** would require a uniform structure of tariffs across EU distribution networks. This option is deemed as not effective in capturing different cost structures and various differences in terms of technical characteristics which determine the final tariff structure. For instance, the possible definition of specific tariff structures under this option would imply the introduction of specific rules for the allocation of distribution costs in different tariff components (e.g. capacity and energy components); however, a uniform tariff structure could not accurately reflect the different characteristics of individual distribution networks and support general policy objectives under diverse energy systems.

This option would reduce flexibility for Member States, as specific tariff elements would be harmonised at EU level. A potential risk of this Option is that NRAs cannot fully design distribution tariffs tailored to local needs, as they would be bound to a fully harmonized tariff framework. Another issue with harmonisation is that a "one-size-fit-all" framework for distribution tariffs might not exist and this would most probably result in various inefficiencies.

b. Their respective key economic impacts and benefit/cost ratio, cost-effectiveness (efficiency) & Economic impacts

Distribution network tariffs and remuneration of DSOs (tables 1 and 2 in Section 1)

Under **Option 1** Member States will be responsible for the detailed implementation of distribution network tariffs and remuneration for DSOs. A more detailed guidance from the Commission with EU-wide principles on tariff setting could enhance the benefits of this option.

171 **Distribution network tariffs and DSO remuneration**

The adoption of distribution tariffs by NRAs which are cost-reflective and provide efficient economic signals to system users will result in lower system costs. Moreover, the introduction of time-dependent distribution tariffs across all Member States would aim at incentivising demand response, the detailed implementation should be linked to specific needs of each distribution system.

Results of a 2015 study[177] show that a well-defined ToU tariff can indeed provide benefits in terms of CAPEX and OPEX for the distribution grid. The level of impact strongly depends on the specific characteristics of the grid and of the load/generation conditions.

Measures on transparency in tariff setting and distribution costs would increase the performance of the agents involved in the tariff setting process resulting in an overall higher societal benefit.

Option 2 could potentially have similar benefits as Option 1; however, if not well designed, a fully harmonized framework could have negative impacts in some Member States or particular distribution systems as one particular tariff methodology could not accommodate the specificities of different distribution systems.

c. Impacts on public administrations

Impacts on public administration are summarized in Section 7 below.

d. Likely uncertainty in the key findings and conclusions

There is a medium risk associated with the uncertainty of the assessment of costs and benefits of the presented options. However, it is considered that this risk cannot influence the decision on the preferred option as there is a high differentiation among the presented options in terms of qualitative and quantitative characteristics.

e. Which Option is preferred and why?

Distribution network tariffs and remuneration of DSOs (tables 1 and 2 in Section 3.3.1)

Option 1 (both for distribution tariffs and remuneration of DSOs) is the preferred option as it will improve existing framework and provide to Member States and regulators more concrete principles and guidance for tariff setting. Multiple benefits are expected for consumers and resources connected to distribution systems.

3.3.6. <u>*Subsidiarity*</u>

EU has a shared competence with Member States in the field of energy pursuant to Article 4(1) of the Treaty on the Functioning of the European Union (TFEU). In line with Article 194 of the TFEU, the EU is competent to establish measures to ensure the functioning of the energy market, ensure security of supply and promote energy efficiency.

[177] *"Identifying energy efficiency improvements and saving potential in energy networks, including analysis of the value of demand response"* (2015) Tractebel, Ecofys.

Under the energy transition distribution grids will have to integrate even higher amounts of RES E generation, while new technologies and new consumption loads will be connected to the distribution grid. Distributed generation has the potential directly or through aggregation to participate in national and cross-border energy markets. Moreover, other distributed resources such as demand response or energy storage can participate in various markets and provide ancillary services to the system also with a cross-border aspect.

The access conditions, including distribution tariffs, for suppliers, aggregators, RES E generation, energy storage etc. shall be transparent and ensure a level playing field. As the amount of resources such as RES E generation, but in the future also other resources such as storage, will increase, the conditions under which these resources can access the grid and participate in the national and cross-border energy markets is expected to become more relevant.

Putting in place EU-wide principles on remuneration schemes will contribute in lowering the costs of distribution and support the deployment of flexibility services across the EU. Incentivising efficient operation and planning of distribution networks will result to an overall reduction of distribution costs which will facilitate the cost-efficient integration of distributed generation and support the achievement of EU RES targets. Moreover, through common principles for incentivising research and innovation in distribution grids, can have positive for European industry and contribute to employment and growth in the EU.

Distribution tariff issues may affect the development of the internal energy market and raise concerns over possible discrimination among system users of the same category (e.g. tariffs applied asymmetrically in border regions). Uncoordinated, fragmented national policies for distribution tariffs may have indirect negative effects on neighbouring Member States and distort the internal market, while lack of appropriate incentives for DSOs may slow down the integration of RES, and the uptake of innovative technologies and energy services. EU action therefore has significant added value by ensuring a coherent approach in all Member States.

3.3.7. *Stakeholders' opinions*

3.2.7.1. *Results of the consultation on the new Energy Market Design*

As concerns a European approach on distribution tariffs, the results of the public consultation on a new Energy Market Design[178] were mixed; the usefulness of some general principles is acknowledged by many stakeholders, while others stress that the concrete design should generally considered to be subject to national regulation.

Distribution tariffs

Question: *"Shall there be a European approach to distribution tariffs? If yes, what aspects should be covered; for example, framework, tariff components (fixed, capacity vs. energy, timely or locational differentiation) and treatment of own generation?"*

[178] https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

Summary of findings:

There are split views among the respondents regarding an EU approach to distribution network tariffs. Some stakeholders (e.g. part of electricity consumers) believe that some degree of harmonisation across EU would be beneficial and reduce barriers to cross-border trade. However, only half of them advocate for a full harmonisation (e.g. specific tariff structures), while the other half is more in favour of EU wide principles.

The electricity industry and few Member States are among those who consider that setting out common principles at EU level is more advisable than a full harmonised framework for distribution network tariffs.

On the other hand, regulators, the majority of Member States and some electricity consumers, do not perceive that a "one fits all" solution is appropriate for distribution network tariffs.

All stakeholders agree that future tariff design should ensure cost efficiency and a fair distribution of network costs among grid users. The electricity industry supports the importance of the capacity, time and location tariff components in order to enhance network price signals and stimulate flexibility.

Member States:

National governments agree that distribution network tariffs should stimulate efficiency and be cost-reflective, with the possibility to easily adapt to market developments. National decisions on tariff structure and components are currently related to the division of network costs among the different system users and to the national distribution system characteristics (size and structure of the grid, demand profile of consumer, generation mix, extent of smart metering, approach to distributed generation), as well as to the different regulatory frameworks (number and roles of DSOs, national or regional distribution tariffs). Therefore, the majority of Member States consider that no further harmonisation of distribution tariffs at EU level is required (e.g. France, Sweden, Finland, Malta, Czech Republic).

Some national governments are however more open to some common approach at EU level. The Polish government proposes the possibility of continuous exchange of regulatory experience between NRAs and information on specific tariff parameters. The Slovak Republic would consider as beneficial a non-binding ACER recommendation on a methodology for distribution tariffs for NRAs, which should incentivise innovation while guaranteeing timely recovery of costs of distribution and efficient allocation of distribution costs. The Danish government suggests that a common framework would increase market transparency from a retail market perspective and would be a first step to harmonisation.

All national governments consider that any European harmonisation or framework for distribution tariffs should not preclude the differences in national policies nor prevent experimental tariff structures aiming at fostering demand side response.

Regulators:

Regulators do not perceive that “one size fits all” approach as appropriate for distribution tariffs. According to them, future tariff designs need to meet the following objectives:

- To encourage efficient use of network assets;
- To minimize the cost of network expansion;

- To seek a fair distribution of network costs among network users;
- To enhance the security and resilience of existing networks;
- To work as a coherent structure, consistent with other incentives.

Electricity consumers:

Some electricity consumers (BEUC, CEPI) advocate a design of distribution grids tariffs which encourage flexibility, reflecting the various profiles of demand response operators (e.g. ranging from industrial production sites to households running their solar PV unit). They argue that a differentiated set of price signals would incentivise demand side flexibility, but that distribution tariffs should comply with EU energy policy and that regulators should have a common understanding of the reward benefits.

Other electricity consumers (CEFIC, IFIEC) believe that harmonising the tariff methodology and structure would be beneficial and reduce barriers to cross-border trade. They support a fair distribution of grid costs between grid users and not leading to cost inefficiencies, and incentives to operators and system users in order to reduce total costs of the electricity system.

European Aluminium is in favour of a harmonized methodology for grid tariffs for the power intensive industry based on the properties and the contribution of the power consumption profile to the transmission system. Such a tariff system must, however, take into account national differences in grid system and market liquidity and maturity.

On the other hand, EURACOAL, EUROCHAMBERS and Business Europe disagree with a harmonization approach because it would not take into account the geographic, environmental, climate and energy infrastructure differences between Member States.

Energy industry:

Most of the stakeholders agree that an EU full harmonization approach to distribution tariffs is not advisable, while some common EU principles are a more preferable approach. In particular, EWEA advocates that the Commission should encourage NRAs in identifying "best practices" rather than imposing a top down harmonisation of distribution tariffs.

ESMIG, instead, believes that a more uniform approach across the EU would be beneficial.

A number of the respondents support the importance of the capacity (CEDEC, ENTSO-E, Eurelectric, ETP, GEODE), time (CEDEC, EASE, ETP, EWEA, GEODE) and location (CEDEC, ETP, EWEA, ENTSO-E) tariff components in order to enhance the network price signals and stimulate flexibility.

The energy industry stakeholders consider that network tariffs shall reflect cost-efficiency and fairness between consumers. They view self-generation as a positive development, but support that prosumers should contribute to the costs of back-up generation and grid costs and avoid that other consumers bear the burden of grid costs. In addition, they support that system charges and other levies linked to policy costs should not artificially increase the cost of electricity, acting as a bias penalizing consumption.

Network charges should provide DSOs with the required revenue to ensure that sufficient network investments are realized and especially investments in smart grids and in operational expenses improvements.

ESMIG advocates for the consideration of a "performance-based" approach, such that the DSOs remuneration would be based on the performance of the network rather than the volume of electricity.

3.2.7.2. *Public consultation on the Retail Energy Market*

Regarding distribution network tariffs, 34% of the respondents to the 2014 public consultation on the Retail Energy Market[179] consider that European wide principles for setting distribution network tariffs are needed, while another 34% are neutral and 26% disagree.

Time-differentiated tariffs are supported by ca 61% of the respondents, while the majority of stakeholders consider that cost breakdown (78%) and methodology (84%) of distribution network tariffs should be transparent.

The majority of stakeholders also consider that self-generators/auto-consumers should contribute to the network costs even if they use the network in a limited way. To this end, ca 50% of the respondents consider that the further deployment of self-generation with auto-consumption requires a common approach as far as the contribution to network costs is concerned.

3.2.7.3. *Electricity Regulatory Forum - European Parliament*

Relevant conclusions of the 31st EU Electricity Regulatory Forum:

- *"The Forum stresses the importance of innovative solutions and active system management in distribution systems in order to avoid costly investments and raise efficiencies in system operation. It highlights the need for DSOs to be able to purchase flexibility services for operation of their systems whilst remaining neutral market facilitators, as well as the need to further consider the design of distribution network tariffs to provide appropriate incentives. The Forum encourages regulators, TSOs and DSOs to work together towards the development of such solutions as well as to share best practices."*

European Parliament resolution of 26 May 2016 on delivering a new deal for energy consumers (2015/2323(INI)):

> *"24. Calls for stable, sufficient and cost-effective remuneration schemes to guarantee investor certainty and increase the take-up of small and medium-scale renewable energy projects while minimising market distortions; calls, in this context, on Member States to make full use of de minimis exemptions foreseen by the 2014 state aid guidelines; believes that grid tariffs and other fees should be transparent and non-*

[179] https://ec.europa.eu/energy/en/consultations/consultation-retail-energy-market

discriminatory and should fairly reflect the impact of the consumer on the grid, avoiding double-charging while guaranteeing sufficient funding for the maintenance and development of distribution grids; regrets the retroactive changes to renewable support schemes, as well as the introduction of unfair and punitive taxes or fees which hinder the continued expansion of self-generation; highlights the importance of well-designed and future-proof support schemes in order to increase investor certainty and value for money, and to avoid such changes in the future; stresses that prosumers providing the grid with storage capacities should be rewarded;"

3.4. Improving the institutional framework

3.4.2. *Summary Table*

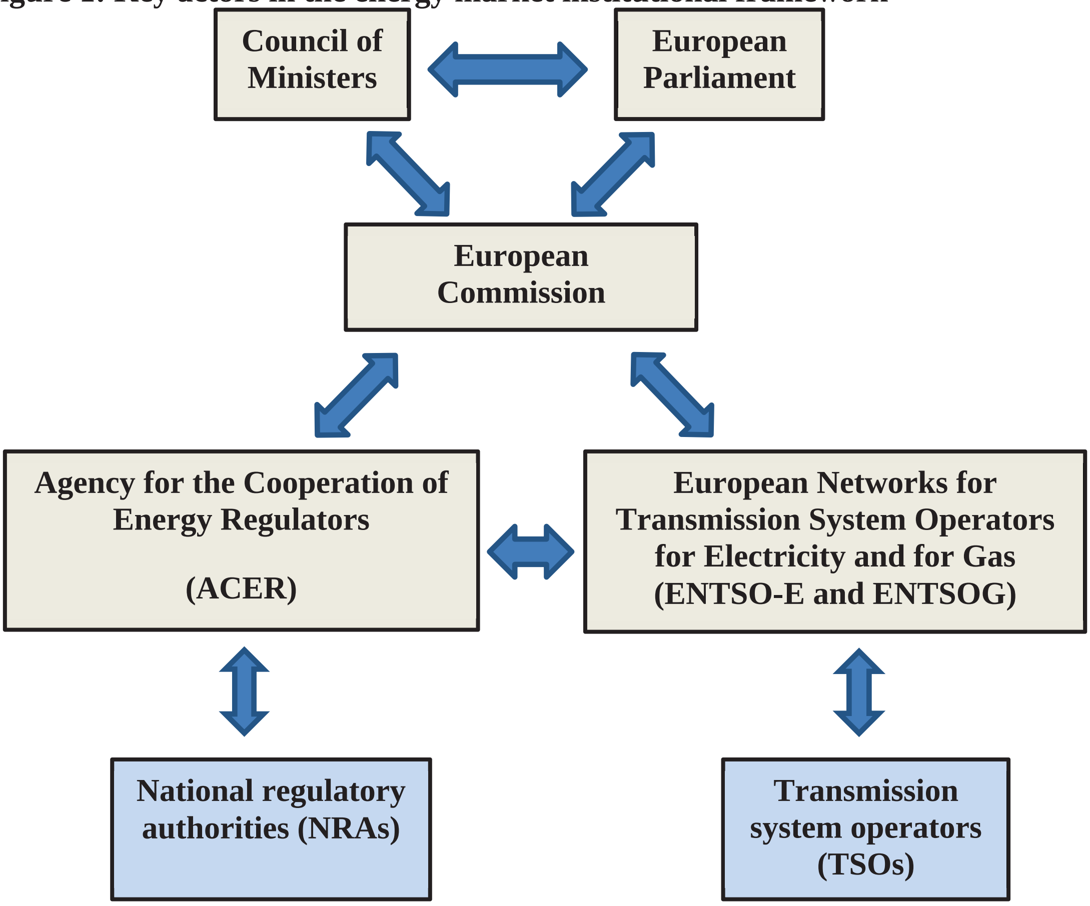
Objective: To adapt the Institutional Framework, in particular ACER's decision-making powers and internal decision-making to the reality of integrated regional markets and the proposals of the Market Design Initiative, as well as to address the existing and anticipated regulatory gaps in the energy market.			
	Option 0	**Option 1**	**Option 2**
Description	Maintain *status quo*, taking into account that the implementation of network codes would bring certain small scale adjustments. However, the EU institutional framework would continue to be based on the complementarity of regulation at national and EU-level.	Adapting the institutional framework to the new realities of the electricity system and to the resulting need for additional regional cooperation as well as to addressing existing and anticipated regulatory gaps in the energy market.	Providing for more centralised institutional structures with additional powers and/or responsibilities for the involved entities.
Pros	Lowest political resistance.	Addresses the shortcomings identified and provides a pragmatic and flexible approach by combining bottom-up initiatives and top-down steering of the regulatory oversight.	Addresses the shortcomings identified with limited coordination requirements for institutional actors.
Cons	The implementation of the Third Package and network codes is not sufficient to overcome existing shortcomings of the institutional framework.	Requires strong coordination efforts between all involved institutional actors.	Significant changes to established institutional processes with the greatest financial impact and highest political resistance.
Most suitable option(s): Option 1, as it adapts the institutional framework to the new realities of the electricity system by adopting a pragmatic approach in combining bottom-up initiatives and top-down steering of the regulatory oversight.			

3.4.1. *Description of the baseline*

The institutional framework currently applicable to the internal energy market is laid out in the Third Package. It strengthened the powers and independence of national regulatory authorities (NRAs) and mandated the creation of an Agency for the Cooperation of Energy Regulators (ACER) and the European Networks of Transmission System Operators (ENTSOs)[180], with the overarching aim of fostering cooperation amongst NRAs as well as between transmission system operators (TSOs) at regional and European level.

Figure 1 below illustrates the key actors in the energy market based on the institutional framework introduced with the adoption of the Third Package.

Figure 1: Key actors in the energy market institutional framework



Source: European Commission

[180] As the current Impact Assessment and the related legislative proposals focus on the European electricity markets, this Annex focuses on the assessment of the options with regard to the ENTSO for Electricity (ENTSO-E).

With the creation of ACER, the Third Package sought to cover the regulatory gap concerning electricity and gas cross-border issues. Prior to the adoption of the Third Package, this regulatory gap had been tackled with the Commission self-regulatory forums like the Florence (electricity) forum and the Madrid (gas) forum as well as through the independent regulatory advisory group on electricity and gas set up by the Commission in 2003, the *"European Regulators Group for Electricity and Gas"* (ERGEG). ERGEG's work positively contributed to market integration. However, it was widely recognised by the sector – and by ERGEG itself – that cooperation between NRAs should be upgraded and should take place within an EU body with clear competences and with the power to adopt regulatory decisions.

To this end, the Third Package entrusted ACER with a wide range of tasks and competences, including:

- promoting cooperation between NRAs;
- participating in the development and implementation of EU-wide network rules (network codes and guidelines);
- monitoring the implementation of EU-wide 10-year network development plans;
- deciding on cross-border issues if national regulators cannot agree or if they jointly request ACER to intervene;
- monitoring the functioning of the internal market in electricity and gas; and
- oversight over ENTSOs.

Based on the adoption of subsequent legislation on market transparency[181] and trans-European infrastructures[182] ACER has been given additional responsibilities in these areas.

The Third Package established ACER with the main mission to ensure that regulatory functions performed by NRAs at national level are properly coordinated at EU level and, where necessary, completed at EU level. As regards its governance structure[183], ACER comprises a Director, responsible for representing the Agency, for the day-to-day management and for tabling proposals for the favourable opinion of the Board of Regulators[184]. ACER's regulatory activities are formed in the Board of Regulators, composed of senior representatives of the NRAs of the 28 Member States. Its administrative and budgetary activities fall under the supervision of an Administrative Board, whose members are appointed by European Institutions. The Board of Appeal is part of the Agency but independent from its administrative and regulatory structures, and deals with complaints lodged against ACER decisions[185]. As regards the internal

[181] Regulation EU No 1227/2011 on Wholesale Energy Market Integrity and Transparency – REMIT; OJ L 326, 8.12.2011, p.1

[182] Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure (TEN-E Regulation).

[183] See Article 3 of the ACER Regulation and related provisions.

[184] Under Articles 5, 6, 7, 8 and 9 of the ACER Regulation.

[185] The ACER Board of Appeal takes its decisions with qualified majority of at least four of its six members; it convenes when necessary; its members are independent in their decisions; some of its costs are envisaged in the ACER budget.

decision-making, ACER decisions on regulatory issues (e.g. opinion on network codes) require the favourable opinion of the Board of Regulators, which decides with two-thirds majority.

In relation to the creation of ENTSOs, the Third Package sought to enhance effective cooperation among TSOs in order to address the shortcomings and limitations shown by the voluntary initiatives adopted by TSOs (the European Transmission System Operators and Gas Transmission Europe). As a result, the Third Package tasked the ENTSOs with EU-level functions such as contributing to the development of EU-wide network rules, developing the 10-year network development plan and carrying out seasonal resource adequacy assessments.

The establishment of ACER and the ENTSOs in order to enhance the cooperation among NRAs and TSOs from 28 different Member States has undoubtedly been successful. Both ACER and the ENTSOs are important partners in discussions on regulatory issues. Further, the Third Package established a framwork for the ACER oversight of ENTSO-E, tasking ACER e.g. with providing opinions on ENTSO-E's founding documents, on the network code and network planning documents developed by ENTSO-E. In addition, the Agency has the obligation to monitor the execution of the tasks of ENTSO-E[186].

As regards its financing, ACER benefits from a Union subsidy set aside specifically in the general budget of the European Union, like most EU decentralised agencies. In addition, ACER can collect fees for individual decisions[187].

Network Codes and Guidelines

The Third Package has set out a framework for developing network codes with a view to harmonising, where necessary, the technical, operational and market rules governing the electricity and gas grids. Under this framework, ACER, the ENTSOs and the European Commission have a key role and need to work in close cooperation with all relevant stakeholders on the development of network codes. The areas in which network codes can be developed[188] are set out in Article 8(6) of the Electricity Regulation and of the Gas Regulation. Once adopted, these network codes become binding Commission Regulations, directly applicable in all Member States.

The network code process is defined in Articles 6 and 8 of the Electricity and the Gas Regulations and it can be essentially divided in two phases: (i) the development phase; and (ii) the adoption phase.

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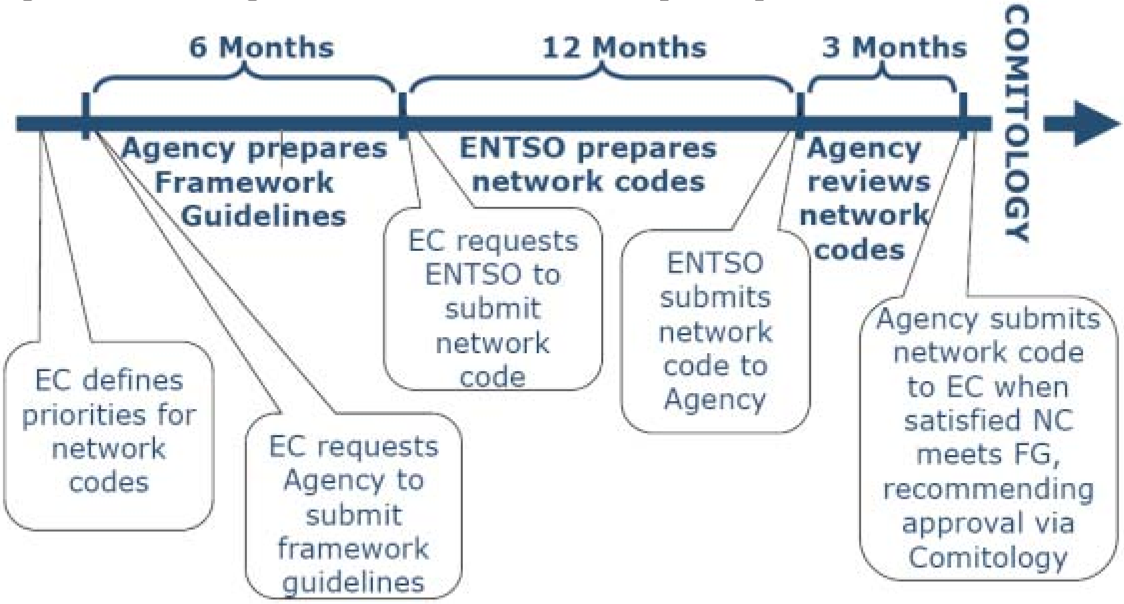
186 Art. 6 of ACER Regulation.

187 Art. 22 of ACER Regulation. However, the fee has to be set by the European Commission, which did not take place yet.

188 E.g., network connection, third party access, interoperability capacity allocation and congestion management rules, etc.

Figure 2 below illustrates the main stages of the network code development phase. It is important to note that during each of these stages, the Commission, ACER and the ENTSOs consult the proposals with stakeholders[189].

Figure 2: Main stages of the network code development process



Source: ACER

Once ACER submits a network code to the Commission recommending its adoption, the Commission starts the adoption phase ("Commission adoption phase"), illustrated in **Figure 3**[190].

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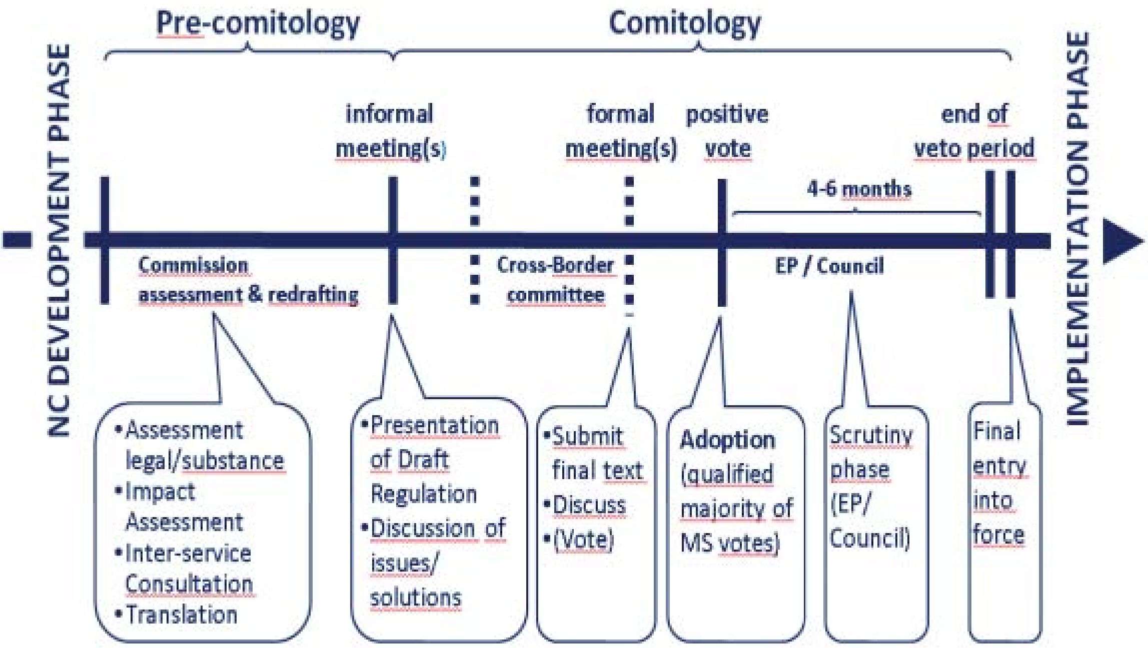
[189] These stakeholder consultations are not always required. For example, consultation is a requirement as regards the preparation of the annual priority list (see Art. 6(1) Electricity Reg.) and the preparation of the framework guidelines (Art. 6(3) Electricity Reg.). During the preparation of the network codes, the ENTSOs have carried out stakeholder workshops, although this is not formally required in the Electricity or Gas Regulations. In addition, the Agency may consult with stakeholders during the 3 months period for revision of the ENTSO proposal and the preparation of the reasoned opinion (Art. 6(7) Electricity Reg.).

[190] Network codes are adopted according to Art. 5a (1) to (4) of Decision 1999/468/EC ("*regulatory procedure with scrutiny*"), which requires a positive vote by a qualified majority of Member States and agreement from Council and Parliament.

Figure 3: Network code adoption phase



Source: unknown

The European Commission has also the possibility to develop "guidelines" which, similarly to network codes, form legally binding Commission Regulations. The guidelines have a different legal basis and follow a different development process[191], under which there is no formal role for ACER or ENTSO-E, while their adoption phase is the same as for the network codes.

Once adopted, network codes and guidelines are both acts implementing the Electricity and the Gas Regulations. There is no difference as concerns their legally binding effects and direct applicability.

3.4.2. *Deficiencies of the current legislation*

The Third Package institutional framework aims at fostering the cooperation of NRAs as well as between TSOs. Since their establishment, ACER and the ENTSOs have played a key role in the progress towards a functioning internal energy market. In 2014, the Commission undertook its first evaluation of the activities of the Agency[192] and concluded that ACER has become a credible and respected institution playing a

[191] The areas in which guidelines can be developed are set out in Art. 18 (1), (2), (3) Electricity Regulation and Art. 23 (1) Gas Regulation.

[192] In line with Art. 34 ACER Regulation. The Commission prepared this evaluation with the assistance of an independent external expert and including a public consultation. The evaluation covered the results achieved by the Agency and its working methods.

prominent role in the EU regulatory field while focusing on the right priorities[193]. Also, according to ACER[194], both ENTSOs have achieved a good level of performance since their establishment by the Third Package.

However, the recent developments in the European energy markets that the current Impact Assessment reflects upon and the related proposals of the Market Design Initiative require the adaptation of the institutional framwork. In addition, the implementation of the Third Package has also highlighted areas with room for improvement concerning the framework applicable to ACER and the ENTSOs.

The Agency has limited decision-making powers, as it acts primarily through recommendations and opinions. With the integration of the European electricity markets more and more cross-border decisions will be necessary (e.g. market coupling). Such decisions however require a strong regulatory framework, for which a fragmented national regulatory approach has proved to be insufficient[195]. Ultimately this fragmented regulatory oversight might constitute a barrier to the integration of the energy markets[196]. In this regard, there is consensus among market parties and stakeholders that ACER should indeed be enabled to more efficiently deal with cross-border issues[197] and to take decisions[198].

Moreover, as European energy markets are more and more integrated, it is crucial to ensure that ACER can function as swiftly and as efficiently as possible. As most of the

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193 *"Commission evaluation of the activities of the Agency for the Cooperation of Energy Regulators under Article 34 of Regulation (EC) 713/2009"* (22. 1. 2014), European Commission, https://ec.europa.eu/energy/sites/ener/files/documents/20140122_acer_com_evaluation.pdf

194 *"Energy Regulation: A Bridge to 2025 Conclusions Paper"* (19 September 2014) ACER Report.

195 The existing competences of ACER for taking decisions set out in the ACER Regulation do not include the implementation of network codes and guidelines. Many trading or grid operation methods to be developed under network codes or guidelines require common EU-wide decisions or regional decisions. Given that ACER does not have competence to take EU-wide or regional decisions relating to network codes and guidelines, currently NRAs have to decide unanimously on the adoption of identical legal acts in all national legal systems within a six-month period. This renders the implementation of network codes and guidelines complex and inefficient.

196 *"Energy Union. Key Decisions for the Realisation of a Fully Integrated Energy Market"* (2016), Study for the Committee for Industry, Research and Energy of the European Parliament: "*In several regional or EU-level projects (e.g. market coupling projects, see our case study in Annex 3) national authorities, TSOs, regulators and energy exchanges of different Member States need to cooperate. However, as they are primarily responsible for their own national gas and electricity system and market they are not always sufficiently motivated to also take supranational interests into account.* […] *This leads to complex and slow decisional and implementation processes for most cross-border projects, resulting in delayed implementations (e.g. the intra-day markets' coupling project)*." In this context, different stakeholders argue for stronger governance at EU level. For example, EPEX Spot states the need to accompany the electricity EU target model by appropriate governance architecture at European level, applicable on market coupling activities, which will be crucial to ensure an efficient day-to-day operation of such complex mechanisms.

197 *"Energy Union. Key Decisions for the Realisation of a Fully Integrated Energy Market"* (2016), Study for the Committee for Industry, Research and Energy of the European Parliament.

198 For instance, the Third Package does not define a regional regulatory framework beyond the generic reference to the need for NRAs to cooperate at regional level supported by ACER, which would be necessary to ensure proper oversight of regional entities or functions.

regulatory decisions require the favourable opinion of the Board of Regulators, it is equally relevant that the NRAs represented in the Board of Regulators can find agreements swiftly and efficiently, which in the past was not always the case, leading to delays or to a situation where the sufficient majority could not be reached, making it impossible for ACER to fulfil its role.

As mentioned in Section 2 above, the Third Package introduced network codes as tools for developing EU-wide technical, operational and market rules. While this process has proved very sucessful overall, the practice of the last 5 years has highlighted the existence of structural insufficiences. As an example, ENTSO-E plays a central role in developing EU-wide market rules. Therefore, the rules on its independence and transparency have to be strong and have to be accompanied by appropriate oversight rules to ensure the transparent and efficient functioning of the organisation. The reinforcement of these rules was also strongly requested by a high number of stakeholders in the Commission's public consultation on the market design initiative. Some stakeholders have mentioned that there is a possible conflict of interest in ENTSO-E's role – being at the same time an association called to represent the public interest involved e.g., in network code drafting, and a lobby organisation for TSOs with own commercial interests – and requested the adoption of measures to address this conflict[199].

The Third Package also includes elements of oversight of ENTSO-E by ACER. However, given the strong role ENTSO-E plays as a technical expert body, in particular in the development and implementation of network codes and guidelines, ACER's oversight has proved to be insufficient, for example as regards ENTSO-E's statutory documents or as regards the delivery of data to the Agency[200]. Moreover, the emergence of new entities and functions of EU-level or regional relevance through the adoption of network codes and guidelines has further enlarged this oversight gap. This is, for example, the case with the nominated electricity market operators ('NEMOs'), the market coupling operator ('MCO') function, which will together be responsible for performing cross-border day-ahead and intraday trading, a role created under the CACM Guideline, and regional security coordinators ('RSCs') in electricity. The creation of these new entities and functions has not been accompanied by tailored regulatory oversight.

The ACER Board of Appeal has a crucial function in safeguarding the validity of the Agency's decisions. Even though the Board of Appeals has been called upon only in a very limited number of times since the establishment, it has proved that its independence is crucial. Experience shows that its functioning and financing must be reaffirmed to ensure its full independence and efficiency.

[199] For example by Eurelectric, EFET, CEDEC, Europex. This issue was also raised among the observations of the European Court of Auditors in its report *"Improving the security of energy supply by developing the internal energy market: more efforts needed" (2015)*, which stated: *"This is problematic because, although the ENTSOs are European bodies with roles for the development of the internal energy market, they also represent the interests of their individual members."*

[200] ACER exerts limited oversight (opinion on status, list of members and rules of procedures as per Art. 5 of the Electricity Regulation and monitoring of ENTSO-E's tasks as per Art. 9 of the Electricity Regulation.

Like most of the EU decentralised agencies, ACER benefits from a Union subsidy set aside specifically in the general budget of the European Union. As explained in Section 2, ACER has been tasked with additional functions since its establishment. These tasks have been accompanied with additional staff. However, ACER is also subject to the programmed reduction of staff in decentralised agencies by 5% over a period of 5 year set out in the Commission's communication on *"Programming of human and financial resources for decentralised agencies 2014-2020"*[201]. It is clear that any additional tasks for ACER as envisaged in the proposed initiatives will further tighten its financing and staffing and will require further resources.

Another set of shortcomings can be tracked to insufficient participation of DSOs within the institutional framework. Under the energy transition, a traditional top-down, centralised electricity distribution system is being outpaced by more decentralised generation and consumption. The integration of a significant share of variable solar and wind generation capacity connected directly to distribution networks create new requirements and possibilities for DSOs, who will have to deal with increased capacity while maintaining quality of service and minimizing network costs. In addition, the electrification of sectors such as transport and heating will introduce new loads in distribution networks and will require a more active operation and better planning.

The problem is aggravated by the fact that specific requirements on TSO – DSO cooperation as set forth in the different Network Codes and Guidelines, and new challenges that TSOs and DSOs are jointly facing, will require greater coordination between system operators.

For the time being, no provision at all is made for the formal integration of DSOs into the EU institutional decision making. However, from a policy perspective a cohesive and consistent participation of DSOs in the EU institutional framework is required. Future electricity system will require a more coordinated approach of TSOs and DSOs on issues of mutual concern. Regarding network codes, DSOs will need to display a common approach, as many of the envisaged network codes are directly or indirectly concern distribution grids.

As set out in the evaluation report[202], while the principles of the Third Package achieved its main purposes, new developments in electricity markets led to significant changes in the market functioning in the last five years. The existing rules defining the institutional framework are not fully adapted to deal with the recent changes in electricity markets effectively. Therefore, it is reasonable to update these rules so that they may be able to cope with the reality of today's energy system.

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201 Communication from the Commission to the European Parliament and the Council, COM(2013)519 final of 10.07.2013.

202 Evaluation Report covering the evaluation of the EU's regulatory framework for electricity market design and consumer protection in the fields of electricity and gas and evaluation of the EU rules on measures to safeguard security of electricity supply and infrastructure investment (Directive 2005/89).

The institutional framework currently applicable to the internal energy market as set out in the Third Package is based on the complementarity of regulation at national and EU-wide level. In view of the developments since the adoption of the Third Package as described in the evaluation report, the institutional framework, especially as regards cooperation of NRAs at regional level, will need to be adapted to ensure the oversight of entities with regional relevance. Moreover, as the European energy markets are more and more integrated, it is crucial to ensure that ACER can function as swiftly and as efficiently as possible. In addition, the implementation of the Third Package has highlighted areas with room for improvement concerning the framework applicable to ACER and the ENTSOs.

3.4.3. *Presentation of the options*

Option 0: Business as usual

The business as usual (BAU) option does not foresee new, additional measures to adapt or improve the institutional framework. Apart from the continued implementation of the Third Package and the implementation of network codes and guidelines, this option would leave the EU institutional framework unchanged, meaning that it would continue to be primarily based on a close complementarity of regulation at national and EU-wide level.

The challenges arising through the changes to and the stronger integration of the European energy markets could not be tackled and regulatory gaps arising from the adoption and implementation of network codes and guidelines would also remain unaddressed. This could potentially lead to delays in their implementation and ultimately act as a barrier to achieving the electricity EU target model.

The BAU option would maintain the limitation of ACER's decision-making powers and would not remedy the risks arising from the fragmented national regulatory approach. NRAs and ACER would continue to face difficulties fulfilling their tasks that have relevance at regional and EU level.

The business as usual option would leave ACER's current internal decision-making unchanged. This would mean that where the favourable opinion of the Board of Regulators is necessary, this would have to be reached with two-thirds majority facing the risk of delays or lack of agreement.

Under this option the process of developing network codes would remain unchanged. This would allow ENTSO-E to continue playing a very strong role in setting European market rules, going beyond of that providing technical expertise. This option would neither improve the rules on ENTSO-E's transparency and independence nor the rules of ACER's oversight of ENTSO-E. The progress concerning ENTSO-E's transparency would depend on the voluntary initiative of the association. The criticisms to the existence of conflicts of interest regarding the roles of ENTSO-E, particularly as regards the development of network codes, would not be addressed.

Under the Option business as usual, despite having been assigned additional responsibilities since its establishment, ACER would still be constrained by the current regulatory framework as regards the regulatory oversight of new entities and functions performing at regional or EU level.

This Option would maintain the current framework for the functioning of ACER's Board of Appeal. This means that its independent functioning and financing would continue to be highly vulnerable.

The BAU also foresees no integration of DSOs into the institutional decision-making setting as explained under the Section dealing with the shortcomings of current legislation. It is true that in 2015, with the support of the Commission, the four European DSO associations and ENTSO-E established a cooperation platform[203] between TSOs and DSOs at EU level. This cooperation has the objective to work on issues of mutual DSO-TSO concern such as coordinated access to resources, regulatory stability, grid visibility and grid data. However, this cooperation remains purely voluntary in nature with no formal expression in the wider EU decision making setting or ACER.

In sum, European DSOs collaborate through the existing DSO associations but without any legal status at EU institutional level. There is no formal participation in drafting or amending of network codes and guidelines.

Option 0+: Non-regulatory approach

Under this option a "stronger enforcement" approach and voluntary collaboration as a non-legislative measure were considered without foreseeing any new, additional measures to adapt the institutional framework. Improved enforcement of existing legislation would entail the continued implementation of the Third Package and the implementation of network codes and guidelines – as described under option business as usual – combined with stronger enforcement. However, stronger enforcement would not provide any improvement to the current institutional framework as it is already fully implementing the existing legal framework.

Collaboration in the current institutional framework is based on legal obligation. While voluntary cooperation might be possible in areas not covered under the Thrid Energy Package, it would require establishing parallel structures and additional resources without significantly improving the functioning of the current regulatory framework. Therefore, voluntary collaboration is not considered a valid option.

Therefore, the Option 0+ would leave the EU institutional framework unchanged, meaning that it would continue to be based, primarily, on a close complementarity of regulation at national and EU-wide levels. Furthermore, any improvement compared to the current situation would have to stem from voluntary initiatives of the involved bodies. In addition, this option could not provide the necessary solutions arising from the changing market reality as described in this impact assessment. Therefore, this option is discarded as not valuable in providing solutions for the described shortcomings and overall developments.

[203] ENTSO-E, CEDEC, GEODE, EDSO, EURELECTRIC (2015), "*General Guidelines for reinforcing the cooperation between TSOs and DSOs*" (http://www.eurelectric.org/media/237587/1109_entso-e_pp_tso-dso_web-2015-030-0569-01-e.pdf)

Option 1: Upgrade the EU institutional framework

Option 1 foresees adapting the EU institutional framework to the new realities of the electricity system[204] and to the resulting need for additional regional cooperation and to address the existing and anticipated regulatory gaps in the energy market, providing thereby for flexibility by a combination of bottom-up and top-down approaches. Option 1 would adapt the institutional framework set out in the Third Package to address the regulatory gaps materialising through the implementation of the Third Package and resulting from the adoption and implementation of network codes and guidelines. It would also adapt the institutional framework to the new realities of the electricity system and to the resulting need for additional regional cooperation.

As regards ACER's decision-making, Option 1 would largely entail reinforcing its powers to carry out regulatory functions at EU level. In addition, in order to address the existing regulatory gap as regards NRAs' regulatory functions at regional level, the policy initiatives under this option would set out a flexible regional regulatory framework to enhance the regional coordination and decision-making of NRAs. This Option would introduce a system of coordinated regional decisions and oversight for certain topics by NRAs of the region (e.g. ROCs and others deriving from the proposed market design initiatives) and would give ACER a role for safeguarding the EU-interest.

Option 1, while giving ACER additional powers, would also ensure that the Agency can swiftly and effectively reach these decisions in its Board of Regulators. To enable NRAs to take decisions without delay in the BoR, this Option would adapt the BoR internal voting rights. Option 1 also reflects on the necessity to ensure that all (existing and proposed) ACER decisions are subject to appeal and that the ACER Board of Appeal can act fully independently and effectively through adjusting its financing and internal rules.

Further, concerning ACER's competences, Option 1 entails strengthening ACER's role in the development of network codes, particularly as regards giving the Agency more responsibility in elaborating and submitting the final draft of the network code to the Commission, while maintaining ENTSO-E's relevant role as a technical expert. This Option would also involve strengthening ACER's oversight over ENTSO-E. In addition, Option 1 would effectively distinguish ENTSO-E's statutory mandate from defending its member companies' interests by setting out a clear European mandate in the legislation and ensuring more transparency in its decision-making processes.

Under this Option, ACER would receive additional competence to oversee new entities and functions which are not currently subject to regulatory oversight at EU level. This is the case for power exchanges operating in their cross-border functions; they play a crucial role in coupled European electricity markets and perform functions that have characteristics of a natural monopoly. Depending on the type of entity or function and their geographical scope, this Option would either introduce NRAs' coordinated regional oversight with support and monitoring by ACER or ACER oversight with NRAs' contribution.

[204] As further detailed in Section 1 of the main body of this impact assessment.

As described in this Section, Option 1 would give ACER additional tasks and powers while acknowledging that appropriate financing and staffing is key for ACER to perform its role. Therefore, Option 1 foresees additional sources of financing which would be possible either by increasing the EU financing or by introducing co-financing, complementary to the Union financing the sector ACER is supervising[205].

This Option would also include a formal place for DSOs to be represented at EU level, in line with an increase in their formal market responsibilities and role as has been mentioned above. The establishment of an EU DSO entity will enable the development of new policies which can positively affect the cost efficient integration of distributed energy resources including RES E, and which will reinforce the representation and participation of EU DSOs at an institutional European level.

Option 1 thus envisages the establishment of an EU DSO entity for electricity with an efficient working structure. European DSOs will provide experts based on calls for proposals issued by the EU-DSO. European DSOs will participate in financing the EU-DSO entity through a Supporting Board based on the existing EU DSO associations (Eurelectric, EDSO, CEDEC, GEODE).

Tasks of the EU DSO will include:

- Drafting network codes/guidelines following the existing procedures;
- Monitor the implementation of network codes on areas which concern DSOs;
- Deliver expert opinions as requested by the Commission;
- Cooperate with ENTSO-E on issues of mutual concern, such as data management, balancing, planning, congestion, etc.

The EU DSO entity will also work on areas such as DSO/TSO cooperation, integration of RES, deployment of smart grids, demand response, digitalisation and cybersecurity.

Option 2: Restructure the EU institutional framework

Option 2 would significantly restructure the institutional framework, going beyond addressing the regulatory gaps identified above and moving towards more centralised institutional structures with additional powers and responsibilities at European level, particularly as regards the role of ACER and ENTSO-E.

Concerning ACER's powers, Option 2 would extend ACER's decision-making powers to all regulatory issues with cross-border trade relevance. This would result in ACER taking

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[205] The Commission's aim for decentralised agencies is to eliminate EU and national budgetary contributions and wholly finance them by the sector they supervise, see the Mission letter of Commissioner Hill of 1 November 2014. In this sense ACER could be co-financed through the sector it is supervising. In the light of ACER's cruacial role in delivering on the common EU objectives and in particular in protecting the Eurpean energy markets from fraud, the functioning of ACER could be co-financed with contributions from market participants and/or public bodies benefitting from ACER's activities. This would contribute to guaranteeing ACER's full autonomy and independence.

over most NRA responsibilities directly or indirectly related to cross-border and EU-level issues. This Option would further give the ACER Director the power to become the main decision-making instance in the Agency, as opposed to the BoR, possibly with veto powers from the Board of Regulators on certain measures.

As regards ACER's competences, Option 2 would entail a direct oversight over ENTSO-E and over other entities fulfilling EU level or regional functions, giving ACER the power to take binding decisions.

In order for ACER to perform its role under Option 2, it would require a significant reinforcement of ACER's budget and staff as this would make a strong concentration of experts in ACER necessary. Therefore, this option would entail – as foreseen under Option 1 – reinforcing EU funding and the possibility to introduce in addition financing through market players and/or public bodies. As Option 2 would give ACER such strong powers it would also entail a significant reinforcement of the structural set-up of the Board of Appeal to ensure that the appeal mechanism can function independently and effectively because it would potentially face a significantly higher number of appeals due to the increasing number of direct ACER decisions foreseen under this Option.

As regards to ENTSO-E's competences, this option would require a formal separation of ENTSO-E from its members' interest. It would strengthen the independence of ENTSO-E by introducing a European level decision-making body who would have powers to decide on proposals and initiatives without requiring prior TSOs' approval.

With regards to the role of DSOs, the measures included under Option 1 would apply to Option 2 as well. The move to an EU regulator with full powers would however mean that ACER would have to also carry out the oversight of, and entertain relations with, DSOs in a way that is now done at Member State level.

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Improving the institutional framework

Table 2: Detailed overview of the measures proposed under the three options

ISSUE	Option 0: Business as usual	Option 1: Ugrade EU insitutional framework to address regulatory gaps	Option 2: Restructur EU institutional framework
ACER decision-making	Limited, through recommendations and opinions Most regulatory decisions with BoR favourable opinion ACER Director manages ACER and tables proposals for BoR favourable opinion	ACER decisions with BoR favourable opinion, also replacing Guideline implementing "all NRA" decisions at EU and regional levels Framework of regional NRA decision-making with ACER oversight (complementary role to safeguard EU interest)	ACER decision without BoR involvement, mainly by ACER Director
BoR decision-making	$2/3^{rds}$ majority for the most of ACER decisions	Simple majority for most of ACER decisions	$2/3^{rds}$ majority for ACER decisions in a limited instances
Board of Appeal	Independent body for all appeal cases Some of its costs are envisaged in the ACER budget	Independent body for all appeal cases with strengthend framework and separate budget line in the ACER budget	Independent body for all appeal cases with strengthend line of financing and framework
ACER Financing	Community/EU-funding (separate budget line) Possibility for ACER to collect fees for individual decisions	Need for increased financing (possibly through increased EU-funding and possibly co-financing by contributions by market participants and/or national public authorities	Need for significantly increased financing (possibly through increased EU-funding and possibly co-financing by contributions by market participants and/or national public authorities
Network Code development process	Based on ACER's framework guideline ENTSO-E drafts network code (strong role and influence), ACER provides opinion and recommendation to the Commission.	Based on ACER's framework guideline ENTSO-E drafts network code guided by a standing stakeholder body and broad general stakeholder involvement, ACER consolidates the network code and submites the final product to the Commission	Based on ACER's framework guideline ENTSO-E drafts network code with the involvement of standing stakeholder body, ACER consolidates the network code (ACER internal decision without Board of Regulators' favourable opinion) and submites the final product to the Commission
Oversight of ENTSO-E	Limited ACER oversight of ENTSO-E	Strenghtened ACER oversight of ENTSO-E	Strenghtened ACER oversight of ENTSO-

			E
Oversight of new entities	None or limited regulatory oversight (limited rules in network codes and guidelines)	Strenghtened regulatory oversight by NRAs and ACER	ACER direct oversight
ENTSO-E's mission and transparency	Lack of clear European mission and voluntary transparency rules	Codified clear European mission and transparency obligations on its decision-making	Formal separation from its members' interests and creation of a decision-making body
DSO	European DSOs collaborate through the existing DSO associations but without any legal status at EU institutional level. There is no formal participation in drafting or amending of network codes and guidelines	Establishment of an EU DSO entity for electricity with an efficient working structure; European DSOs will provide experts based on calls for proposals issued by the EU-DSO.	Same as Option 1, plus an increased role for coordination and oversight on the part of ACER

Source: European Commission

3.4.4. *Comparison of the options*

As stated above, the goal of the proposed initiatives is to adapt the institutional framework to the reality of integrated regional markets. In this regard, as it will be further illustrated below, Option 0, the business as usual option, would not contribute towards achieving this objective and in some instances it may even be detrimental, since the institutional framework needs to be able to provide tools for the different parties (ACER, NRAs, ENTSO-E) to address the challenges arising from the integration of the markets.

Options 1 and 2 can capture the challenges and potential opportunities, but the efficiency, effectiveness and economic impact of these options can vary significantly.

Table 3: Qualitative comparison of Options in terms of their effectiveness, efficiency and coherence of responding to specific criteria

Criteria	Option 0: Business as usual	Option 1: Upgrade EU institutional framework addressing regulatory gaps	Option 2: Restructure EU institutional framework
Quality	0 Progress remains limited and primarily voluntary	+ Using expertise from established actors	+ Efficient through limited coordination requirements
Speed of implemen-tation	- Slow, primarily voluntary progress	0/+ Building upon established structures	- Delays resulting from changed structure
Use of established institutional processes	- Efficiency of established processses limited.	++ Can build upon established structures	- Requires building up new structures/processes
Efficient organisational structure	0 Existence of insufficient rules and regualtory gaps for organisation	++ Efficient organisational structure can be created; using expertise from established actors further improving it	+ Efficient because of limited coordination requirements
Involvement of stakeholders	0 Process in the hands of the main actors	+ Rules for effective, reinforeced involvement	+ Rules for effective, reinforced involvement

Source: European Commission.

The assumptions in this table are based on the feedback received from stakeholders in their response to the public consultation and from additional submissions from ACER.

Table 4: Qualitative estimate of the economic impact of the Options

	Economic Impact		
	Internal Market for electricity	**Transparency and non-discrimination**	**Administrative impact and implementation costs**
Option 0: Business as usual	0/+	-	0
Option 1: Upgrading EU institutional framework	+	+	0/-
Option 2: Restructuring EU institutional framework	++	++	--

Source: European Commission

The assumptions in this table are based on the feedback received from stakeholders in their response to the public consultation and from estimations concerning the resources of ACER and ENTSO-E.

In summary, Option 0 – business as usual – will fall short in providing for an institutional framework that can underpin the integration of the internal electricity market in a timely manner.

Option 1, addressing regulatory gaps by upgrading the EU institutional framework would be, according to the assessment of the options above, the most appropriate measure for establishing an EU institutional framework that reflects and complements the increasingly integrated and regional dimension of the electricity market. This option is favoured by most of the stakeholders[206]. It represents a flexible approach combining bottom-up initiatives and top-down steering of the regulatory oversight, respecting the principle of subsidiarity.

Option 2, significantly restructuring the EU institutional framework, while having advantages in terms of requiring less coordination and being as efficient as Option 1, it has the clear disadvantage of requiring significant changes to established institutional practices and processes and of having the greatest economic impact. Some of the solutions proposed under Option 2, such as those involving the extension and shifting of decision-making powers and responsibilities, would raise severe opposition from stakeholders. That would be for example the case for ACER and the transfer of decision-

[206] 70% of stakeholders responding to the relevant questions of the Commission's public consultation on a new market design were in favour of strengthening ACER's institutional role, e.g. some mentioning that it may be efficient to enable ACER to take decisions on cross-border issues where EU network codes/guidelines require decisions to be taken by all national regulatory authorities. Further, many stakeholders asked for improving ENTSO-E's independence from its members' commercial interest.

making powers from NRAs[207]. In summary, Option 2 did not receive support from stakeholders.

The Commission Services are of the view that Option 1 "upgrading the EU institutional framework " is currently the most appropriate approach to achieve the main objective pursued i.e., adapt the institutional framework and ACER's decision powers and internal decision-making to the reality of integrated regional markets.

It is also relevant to note, that as the institutional framework for the European energy market design initiative, the proposals discussed above in the options will be accompanied by some further changes originating from the need to adapt ACER's funding Regulation to the Common Approach on EU decentralised agencies[208] and to incorporate some minor improvements to streamline the institutional framework established in the Third Package.

Further, as the Third Package establishes an identical institutional framework for electricity and for gas[209], changes to this system will be also applied to the gas sector where relevant and reasonable to ensure that rules and processes are identical for the two sectors in the future.

3.4.5. *Budgetary implications of improved ACER staffing*

This Section provides an estimate of budgetary implications from adjusting ACER staffing to adequately meet new tasks and responsibilities envisaged under the preferred option (Option 1) as well as under the highly ambitious Option 2.

As per the Agency's draft 2017 Work Programme, ACER employed on 31.12.2015 a total of 54 Temporary Agents, of which 39 at AD level and 15 at AST level. The Agency further employed an additional 20 Contract Agents and 6 SNE, raising the total ACER headcount to 80.

It should be noted that the European Commission, in its latest opinion on the ACER Work Programme[210] did not agree to grant additional staff under the 2017 budget, judging that current staff figures are adequate to meet current tasks and suggesting that ACER shifts resources internally to meet priority objectives.

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[207] Most of the Member States responding to the relevant questions of the Commission's public consultation on a new market design favored preserving the *status quo* as regards the institutional framework.

[208] The Common Approach on EU decentralised agencies agreed in July 2012 by the European Parliament, the Council and the Commission defines a more coherent and efficient framework for the functioning of agencies. Although legally non-binding, it serves as a political blueprint not only guiding future horizontal initiatives but also in reforming existing, individual EU agencies. Most importantly, the implementation of the Common Approach requires the adaptation of the founding acts of existing agencies, based on case by case analysis.

[209] For example, the Third Package, in the Gas Regulation established the European Network for Transmission System Operators for Gas (Art. 5).

[210] Commission Opinion on the draft Work Programme of the Agency for the Cooperation of Energy Regulators, C(2016)3826 of 24.6.2016

In line with additional tasks foreseen under Option 1 and Option 2, ACER staffing resources should however be adapted.

The tables below show the financial implications of Option 1 and Option 2 for extra staff. The average cost per headcount is based on the latest DG BUDGET declared average cost[211]: for a Temporary Agent, total average costs including "bailage" costs (real estate expenses, furniture, IT, etc.), stand at EUR 134.000 per year per individual.

Table 5: ACER staff: budgetary implications under Option 1

Function	**(a) No. extra staff (MIN)**	**(b) No. extra staff (MAX)**	**Budget of (a)** (million euros)	**Budget of (b)** (million euros)
Network Codes and Regulation	7	12	0.938	1.618
Regulatory Oversight	6	10	0.804	1.340
Coordination (Internal and External)	2	3	0.268	0.402
DSO-related	2	3	0.268	0.402
Total	**+ 17**	**+ 28**	**2.278**	**3.752**

Source: Own calculation based on DG BUDG figures

[211] Circular note of DG BUDGET to RUF/2015/34 of 09.12.15

Table 6: ACER staff: budgetary implications under Option 2

Function	(a) No. extra staff (MIN)	(b) No. extra staff (MAX)	Budget of (a) (million euros)	Budget of (b) (million euros)
Network Codes and Regulation	20	30	2.680	4.020
Regulatory Oversight	30	35	4.020	4.690
Dedicated national desk offices	56	84	7.504	11.256
Reinforced Board of Appeal	15	20	2.010	2.680
Coordination (Internal and External) & Management	15	20	2.010	2.680
DSO-related	5	10	0.670	1.340
Total	**+ 141**	**+ 199**	**19.296**	**26.666**

Source: Own calculation based on DG BUDG figures

These calculations are only approximate as they cannot take into account the grade level of future recruited staff or the exact breakdown of future tasks. This is particularly true for Option 2, which would entail a complete overhaul of the Agency and the appropriation of full regulatory competences for 28 markets.

3.4.6. *Subsidiarity*

The current institutional framework for energy in the Union is based on the complementarity of regulation at national and EU level. The Third Package mandated the designation by Member States of national regulatory authorities and required that they guarantee their independence and ensure that they exercise their role and powers impartially and transparently at national level. The Third Package also created ACER and ENTSO-E in order to enhance the coordination of national energy regulators and elecricity TSOs at EU level.

The implementation of the Third Package through the adoption of Commission implementing regulations has led to the creation of new entities and functions which have changed the regulatory landscape. Some of these entities/functions have EU-wide relevance (e.g., the market coupling operator function in the electricity sector) whereas others have regional relevance (e.g., the regional security coordinators in the electricity sector, capacity allocation platforms in the gas sector).

Moreover, the electricity markets have become more integrated due to increasing cross-border electricity trade and more physical interconnections in the European electricity grid. This, together with progressively higher shares of decentralized and variable renewable energy sources, have rendered the national electricity systems much more interdependent than in the past.

Whereas the institutional framework envisaged in the Third Package has undoubtedly been successful, the unprecedented changes described above have highlighted the existence of regulatory gaps. These gaps appear, for example, where the creation of the entities/functions with EU-wide or regional relevance has not been accompanied with the necessary tools to equip ACER with powers to exercise regulatory oversight over them, despite the fact that they will be carrying out monopoly or critical functions for the internal energy market at EU or regional level. Other gaps relate to the lack of regulation ensuring the consistent implementation of governance principles across regions or to the lack of clarity concerning the roles and responsibilities of national regulatory authorities, ACER and ENTSO-E following the adoption of Commission implementing regulations.

It is therefore necessary to adapt the institutional framework in the Third Package to meet this new reality and provide a basis for realizing the full potential of the internal energy market. This is why the roles of NRAs, ACER, and ENTSO-E need to further evolve, clarifying their powers and responsibilities over relevant geographical areas. In addition, it will be necessary to adapt the institutional framework to the changes in EU energy legislation stemming from the proposed initiatives.

Proportionality

Option 1 would be in line with the proportionality principle given that it aims at clearly defining the roles, powers and responsibilities of the main actors (NRAs, ACER, ENTSO-E) so that they are adapted to the new realities of the electricity markets and to the need for more regional cooperation. More specifically:

- The improvements to the ACER framework under this option do not aim at replacing national regulatory authorities but rather at complementing their role as regards issues which have regional/EU-wide relevance. The scope of ACER's responsibilities will continue to be limited to cross-border relevant issues.
- The improvements concerning the regulatory oversight at regional level aim at addressing the regulatory gap that has arisen with the implementation of the Third Package through the adoption of Commission implementing regulations.
- The amendments of the ENTSO-E framework under this option principally aim at improving and clarifying its mandate to ensure its European character and to introduce more transparency in its internal decision-making processes.
- The improvements to the process for developing Commission implementing regulations (network codes and guidelines) aim at addressing some of the shortcomings identified in the past years.
- The establishment of an EU DSO entity will support EU policies and RES integration in the electricity system, will support the swift implementation of network codes and guidelines, and enhance cooperation between TSOs and DSOs.

3.4.7. *Stakeholders' opinions*

This Section provides a more detailed summary of the views expressed by stakeholders regarding the adaptation of the institutional framework in the European Electricity Regulatory Forum and in response to the Commission public consultation on a new market design.

The 29th meeting of the European Electricity Regulatory Forum of 9 October 2015 underlined, as a conclusion, *"the need for analyzing and further elaborating the roles, tasks, responsibilities and consider possible governance structures of ACER and ENTSO-E"* and stressed *"the need to observe and consider possible governance structures for other bodies, including DSOs and power exchanges, and for NEMO cooperation."*

As regards enhancing ACER's institutional role, in response to the Commission public consultation on a new market design, 70% of all stakeholders who answered the questions on ACER wanted to increase the powers or tasks of ACER (notably as regards oversight of ENTSO-E). 30% supported to keep the *status quo*. Only a limited number of respondents (5%) mentioned missing independence of ACER as a problem. In general, views differed between Member States and NRAs on the one hand (rather for preserving *status quo*) and other stakeholders (rather in favour of strengthening powers at regional/EU level).

Within the development of a robust regulatory framework for the entities performing monopoly or near-monopoly functions at EU or regional level, ACER called for the power to exercise regulatory oversight over such entities[212]. With regard to regional cooperation, which should be promoted by the NRAs, ACER can support NRAs' actions and should be responsible for promoting and monitoring the consistency of regional implementation and of the activities of entities performing monopoly or near-monopoly activities at regional level.

As regards ENTSO-E, 38% of the respondents to the public consultation on a new market design did not have or did not express any opinion or preference regarding the possible strengthening of ENTSO-E. Looking at the respondents having an opinion on this topic, 59 % of the respondents were in favour of not to strengthen ENTSO-E while 41% asked for a stronger ENTSO-E.

As regards power exchanges, 63% of the respondents to the consultation answering this specific question were of the view that there is a need for enhanced regulatory oversight of power exchanges.

As regards the process for development of Commission implementing regulations in the form of network codes and guidelines, some of the respondents to the consultation mentioned the existence of a possible conflict of interest in ENTSO-E’s role – being at the same time an association called to represent the public interest, involved e.g. in

[212] ACER's position on the regulatory oversight of (new) entities performing monopoly or near-monopoly functions at EU-wide or regional level.

network code drafting, and a lobby organisation with own commercial interests – and asked for measures to address this conflict. Some stakeholders suggested that the process for developing network codes should be revisited in order to provide a greater a balance of interests. Some submissions advocated for including DSOs and stakeholders in the network code drafting process.

As regards DSOs, the establishment of an independent EU-level DSO entity has been welcomed by stakeholders on multiple occasions. In particular, attention is drawn to the Conclusions of the 31st Energy Regulators Forum, whereby: *"The Forum takes note of the announcement from the Commission of the establishment of an EU- level DSO entity that can serve to provide expertise in advancing the EU market. The Forum invites the Commission, in the design of any entity, to ensure a balanced representation of DSOs and maximum independence and neutrality"*. Equally, regulators (ACER and CEER) suggested considering whether DSOs should be encouraged to establish a single body through which they can more efficiently participate in the process of new electricity market design.

EUROPEAN
COMMISSION

Brussels, 30.11.2016
SWD(2016) 410 final

PART 4/5

COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT

Accompanying the document

Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast)

Proposal for a Regulation of the European Parliament and of the Council on the electricity market (recast)

Proposal for a Regulation of the European Parliament and of the Council establishing a European Union Agency for the Cooperation of Energy Regulators (recast)

Proposal for a Regulation of the European Parliament and of the Council on risk preparedness in the electricity sector

{COM(2016) 861 final}
{SWD(2016) 411 final}
{SWD(2016) 412 final}
{SWD(2016) 413 final}

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4. Detailed measures assessed under Problem Area II, option 2(1); (improved Energy Markets, no CMs)

4.1. Removing price caps

4.1.1. *Summary table*

Objective: to ensure that prices in wholesale markets and not prevented from reflecting scarcity and the value that society places on energy.			
	Option 0: Business as usual	**Option 1: Eliminate all price caps**	**Option 2: Create obligation to set price caps, where they exist, at VoLL**
Description	Existing regulations already require harmonisation of maximum (and minimum) clearing prices in all price zones to a level which takes "into account an estimation of the value of lost load". Non-regulatory approach Enforceability of *"into account an estimation of the value of lost load"* in the CACM Guideline is not strong. Enforcement action is unlikely to be successful or expedient. Relying on stronger enforcement would leave considerable more legal uncertainty to market participants than clarifying the legal framework directly.Voluntary cooperation not provide the market with sufficient confidence that governments would not step in restrict prices in the event of scarcity.	Eliminate price caps altogether for balancing, intraday and day-ahead markets Removes barriers for scarcity pricing Avoids setting of VoLL (for the purpose of removing negative effects of price caps)	Reinforced requirement to set price limits taking "into account an estimation of the value of lost load" Allow for technical price limits as part of market coupling, provided they do not prevent prices rising to VoLL. Establish requirements to minimise implicit price caps.
Pros	Simple to implement – leaves adminstration to technical implementation of the CACM Guideline.	Measure simple to implement; unequivocally and creates legal certainty.	Compatible with already existing requirement to set price limit, as provided for undert the CACM regulation, provides concrete legal clarity
Cons	Difficult to enforce; no clarity on how such clearing prices will be harmonised. Does not prevent price caps being implemented by other means.	Can be considered as non-proportional; could add risk to market participants and power exchanges if there are no limits .	VoLL, whilst a useful concept, is difficult to set in practice. A multitude of approaches exist.
Most suitable Option(s): Option 2 - this provides a proportionate response to the issue –, it would allow for technical limits as part of market coupling and this should not restrict the markets ability to generate prices that reflect scarcity.			

4.1.2. *Description of the baseline*

Scarcity pricing is critical to investment in flexible generation and demand. Traditionally, power plants have been built based on receiving a stable revenue and operating with high levels of output for a significant proportion of time (i.e. high load factors). However, with more variable renewable technologies entering on to the system, with generally very low or zero marginal costs, the patterns that more conventional forms of generation operate (e.g. gas) is changing. Investment will no longer be able to take place based on the assumption that plants will operate at high load factors for a significant portion of their working life; with more and more generation from renewables, with lower running costs, these plants will operate less and less. However, they will remain critical in providing a stable electricity system. They will need to operate to keep supply steady in times of low renewable generation and flexibility will be key. There will be more and more occasions when prices could reach very high levels (in times of scarcity) but for very short periods of time. It is these peaking prices that can provide the signals and stimulate the investment needed in flexible capacity so long as investors have the confidence that they will be able to recoup their money based on such prices. Further, such prices are critical in stimulating other forms of flexibility, notably in the form of demand response – in the case where a consumer (industrial or residential) has a contract which reflects wholesale price movements, the greater the price differences, the greater the incentive to respond by reducing consumption and instead using energy at lower price periods.

It is not the case, however, that all consumers will necessarily see such short-term changes in prices. In general, consumers will be more affected by the longer-term changes in average prices; these will more likely feed through to energy bills for reasons explained below.

Whilst different formulas exist, unit costs in a standard fixed or variable (monthly) retail tariff will be an average of the wholesale price over a period of time, with additional costs added, such as network costs, taxes, etc., along with any supplier margins. Consumers on these tariffs will be shielded from period-by-period changes in the wholesale price, be they up or down.

Whilst the development of demand response will be enhanced by dynamic tariffs which better reflect the wholesale price, there is no proposal for this to be obligatory. If a consumer were to choose a tariff that mirrored the wholesale price on a 1:1 ratio, overtime they would likely pay less as their suppliers would face lower hedging costs, which they could then pass on to those consumers as tariff savings (lower margins). This is illustrated in the Nordic markets, where hourly tariffs are often the cheapest on the market for most consumers. Nevertheless, consumers whose peak consumption consistently coincided with price peaks on the market, and who chose a dynamic tariff, may end up paying more at the end of the billing period, reflecting their cost to the system.

The formation of scarcity prices can be contained directly or indirectly and, in particular, by caps on prices. These can be implemented for a number of reasons, including technical (e.g. required as part of the operation of the programs which determine market results), to improve the robustness of market operation (e.g. to prevent significant errors in bidding affecting market outcomes), for competition reasons (i.e. to limit any abuse of a dominant position), for consumer-related reasons (e.g. to limit consumer exposure to high prices) and for financial reasons (e.g. to limit the collateral needing to be posted).

In a perfect market, supply and demand will reach an equilibrium where the wholesale price reflects the marginal cost of supply for generators and the marginal willingness to pay for consumers. If generation capacity is scarce, the market price should reflect the marginal willingness to pay for increased consumption. As most consumers do not participate directly into the wholesale market, the estimated marginal value of consumption is based on the value of lost load (VoLL). VoLL is a projected value which is supposed to reflect the maximum price consumers are willing to pay to be supplied with electricity. If the wholesale price exceeds the VoLL, consumers would prefer to reduce their consumption, i.e. be curtailed. If, however the wholesale price is lower than the VoLL, consumers would rather pay the wholesale price and receive electricity. If prices are prevented from reaching the VoLL through the introduction of price caps, then short-term prices will be too low in scarcity situations. This in turn can affect investment signals - notably, it can reduce the incentive to investment in flexible capacity (i.e. of the type that can respond to short-term peaks in prices) and demand response.

However, currently all Member States have specific restrictions on the price to which wholesale prices can rise. In the day-ahead market, the most common cap is EUR 3000/MWh, which is by-and-large a technical constraint rather than implemented with the intention of keeping prices below VoLL. Some Member States have values somewhat lower, which could introduce distortions in the price signals.

Figure 1 – Day-ahead price caps

- Majority: +3000 EUR/MWh
- GB: +3000 or +6000 GBP/MWh
- Greece: 150 EUR/MWh
- Ireland: +1000 EUR/MWh
- Poland: 347 EUR/MWh, +3000 EUR/MWh (x-border)
- Portugal/Spain: 180 EUR/MWh

Source: "Market design: Barriers to optimal investment decisions" Impact Assessment support study, (2016) COWI

These values have limited relationship to the value of lost load and, therefore, if maintained would prevent prices rising to the level to which society values energy. For example, a recent study commissioned for the UK's Department of Energy and Climate Change estimated that VoLL for Electricity in Great Britain to be GBP 10,289/MWh for domestic users and GBP 35,488 for SMEs on a winter peak workday (approximately EUR 13,500/MWh and EUR 46,500/MWh at the time of writing)[1]. Whilst VoLL will change depending on the circumstances, the user and the location (it will not be the same in all Member States), it is clearly much higher than the limits that currently exist in many day-ahead markets. Price caps in the intraday markets show a lot less harmonisation - see map below. Whilst the level is generally much higher - i.e. no caps in some countries, and up to EUR 9999,99/MWh in others, and therefore are less likely to create distortions, some Member States have price caps which will fall far below VoLL.

Figure 2 – Intraday price caps

- Green: No ID market
- Light blue: -9999,99 to +9999,99 EUR/MWh
  - Stripes: DE: Discrete -3000/+3000 EUR/MWh
- Dark blue: No price caps
- Czech: +3700 EUR/MWh
- Dark red:
  - GB: 0/+2000 GBP/MWh
  - IT: 0/+3000 EUR/MWh
  - PT, ES: 0/+180 EUR/MWh

Source: "Market design: Barriers to optimal investment decisions" Impact Assessment support study, (2016) COWI

With regards to the balancing timeframe, price caps apply to the activation (energy) part of balancing services in several Member States. In some countries there are fixed price caps, like +/-9999,99 EUR/MWh in Slovenia, +/-3700 EUR/MWh in Czech Republic, or 203 EUR/MWh for FRR in Lithuania. In Austria and the Nordic countries, the floor price is equal to the day-ahead price, meaning that there is a guarantee that the payment for energy injected for balancing is at least equal to the day ahead price. In Belgium,

1 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf

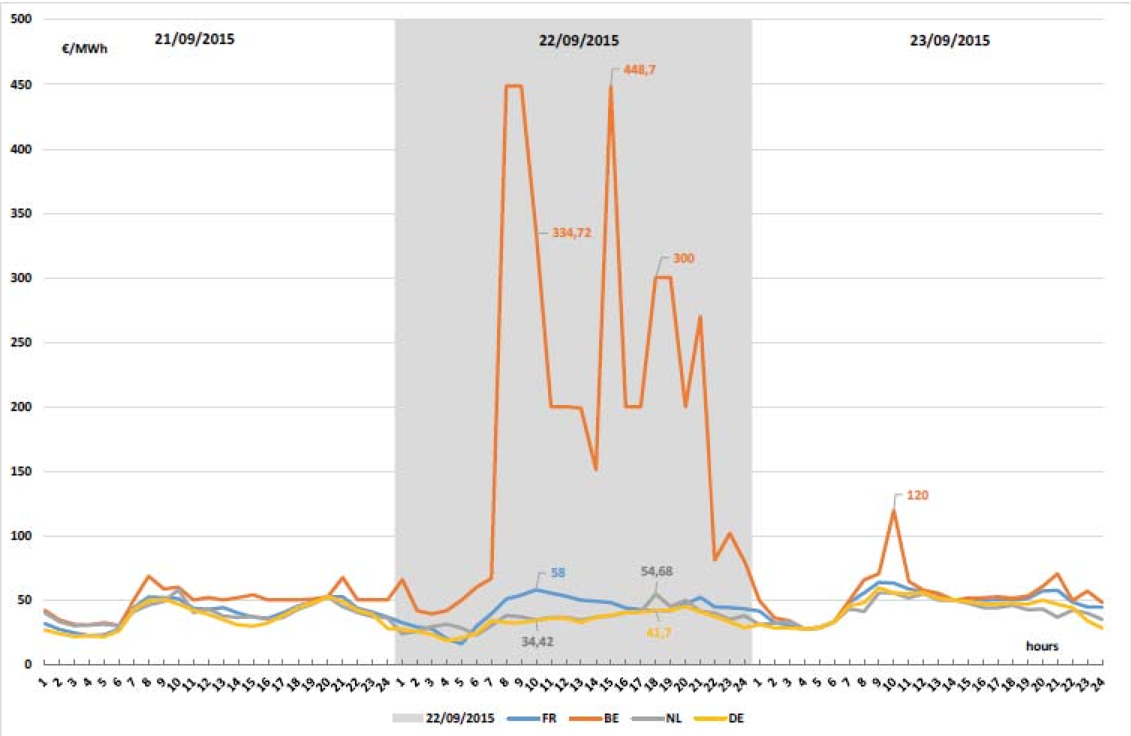
FRR prices are capped to zero (downward regulation) and to the fuel cost of CCGT plus 40 euros (upward regulation). Most Member States do not have price caps for capacity (reserve) bids.

There is an important relationship between the price paid for balancing services and the imbalance price – that is, the price determined by TSOs which producers and consumers must pay as they use or produce too much or too little energy compared to their contracted amount. As detailed further below, it is this real-time price which will have the biggest impact on prices in the intraday, day-ahead and forward prices. However, it will be heavily influenced by the price that TSOs pay for balancing services. In particular, under the upcoming Balancing Guideline, there are restrictions on how it can be formed based on the price paid for activation of balancing energy. The Guideline will also require that there are no caps or floors to balancing energy prices.

Free formation of prices in the balancing market is perhaps the most important issue; day-ahead and intraday markets effectively act as an opportunity to hedge against the expected imbalance price - they will not buy or sell energy above this price as it will be cheaper to be out of balance and pay the imbalance price. Therefore, the balancing price should not mute scarcity pricing by capping prices below VoLL, else prices in the intraday and day-ahead timeframes will not reflect scarcity, regardless of any caps put in place.

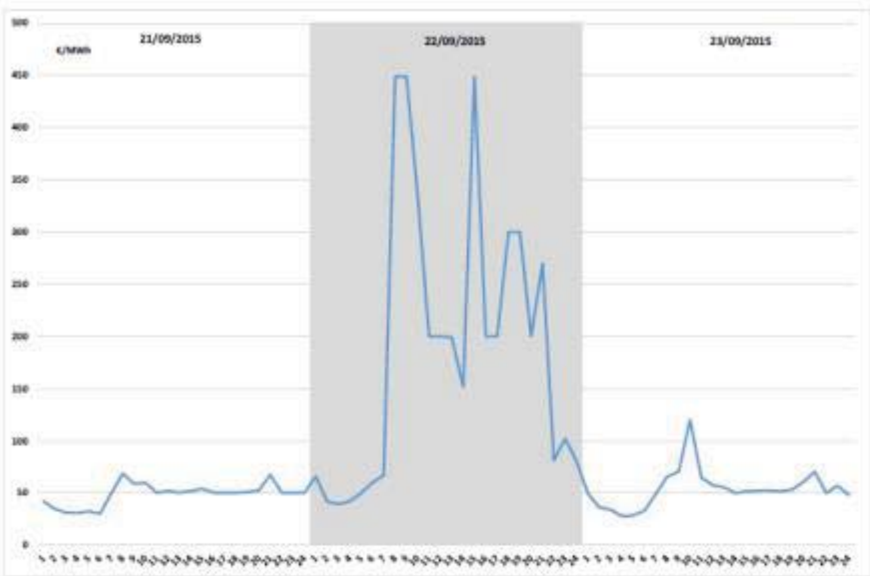
The following diagrams illustrate the relationship between prices in each of the three market timeframes, using the example of the imbalance price in Belgium on the 22nd September 2015. Figure 5 shows a high imbalance price caused by scarcity due to unplanned outages.

Figure 3 – Day-ahead spot prices as a result from the matching of orders in and the coupling of the bidding zones in the CWE-region on the 21st, 22nd and 23rd September 2015



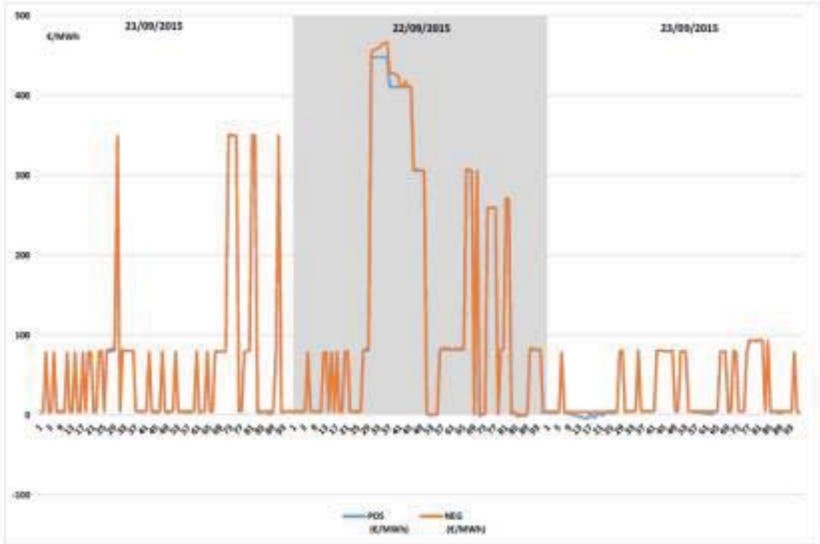
Source: Belpex, EEX, APX

Figure 4 – Intraday prices in Belgium on 21st, 22nd and 23rd September 2015



Source: Belpex

Figure 5 – Imbalance prices in Belgium on 21st, 22nd and 23rd September 2015,



Source: Elia

From these, it can be seen that the market is behaving rationally - i.e. that parties are trading in the day-ahead and intraday markets to hedge themselves. The prices are tracking the imbalance price. If it was prevented from going above a set amount, this would have an effect on bidding behaviour in the other two timeframes, which would also not go above this price. As the imbalance price will change in real time, market participants can only base their bidding in the day ahead and intraday markets based on what they expect the price will be. Therefore, such tracking of prices across timeframes will not happen where there are very short-term changes in the imbalance price, e.g. due to sudden tripping of equipment.

It should be noted that there is a difference between price restrictions on the price paid for activation of energy by TSOs in the balancing timeframe, and the imbalance price.

The former will help inform the imbalance price, but it is generally the latter that has the most impact on behaviour in the day-ahead and intraday market.

Two issues exist relating to harmonisation of caps. Firstly, given the above, that of harmonisation between timeframes. If caps exist in the balancing timeframe, there is little point in having a cap higher than this in intraday or day ahead, as there will be no reason for market parties to bid or offer energy at a higher price - i.e. because it will be cheaper to pay the imbalance price. It is therefore important that there is consistency across market timeframes. The second issue relates to harmonisation between markets. If there are different price caps each side of a border, this can interfere with how energy flows in times of system stress. Take for example Member State A with a price cap of 1000, on a border with a Member States B whose price cap is 100. In the absence of a cap, energy would flow to the country who valued it the most, i.e. with the higher price. However, with these caps if there was a concurrent scarcity event which led to prices going above 100, then energy will always flow to Member State A, despite the fact that Member State B might value energy as much or more (i.e. because the price cannot attract flows of energy more than Member State A's prices).

Implicit price caps can also exist. For example, in some Member States (around a third), a shadow auction[2] is triggered if prices reach 500 euros /MWh (or goes below -150 euros /MWh). This can act as a disincentive to bid higher than EUR 500 . Other disincentives that have been identified include: general fears about competition law – for example, the market restricting itself out of fear of being seen to be abusing a dominant position; the price at which strategic reserves are activated; and TSO actions based on market price.

4.1.3. *Deficiencies of the current legislation*

Current European legislation contains very little reference to wholesale market prices caps. In fact, the only reference is contained in the CACM Guideline. Specifically, Articles 54 (covering intraday trading) and Article 41 (covering day-ahead) require power exchanges, acting in their cross-border roles as NEMOs to propose harmonised maximum and minimum bid prices. This needs to "take into account the value of lost load." This proposal is due to be made to regulatory authorities by mid May 2017.

As pointed out in the Evaluation Report, normally, well-functioning wholesale markets should provide price signals necessary to trigger the right investment. However, the ability of markets to do so is debated today because today's electricity markets are characterised by uncertainties as well as by a number of market and regulatory failures which affect price signals. These include low price caps, renewable support schemes, the lack of short term markets and lack of demand response operators.

[2] Auctions run to validate that the results of the first auction are correct and not abnormal prices due to either technical issues during the execution of the market clearing algorithms, or bidding behaviour of market participants.

4.1.4. *Presentation of the options*

Option 0: Business as usual

The option would allow for the continuation of limits on wholesale prices. This would in principle allow for different price caps in different timeframes. However, under the terms of the CACM Guideline it would bring harmonisation in day-ahead and intraday as there is a requirement for a harmonised value in all bidding zones participating in market coupling. This value would have to "take into account" the value of lost load. It would not, however, have to represent this value and could be significantly lower. For example, as part of the NWE market coupling project, there is a maximum clearing price of 3000euros/MWh in those bidding zones taking part in the project. This limit has been applied to other markets, for example the German intraday auction (which takes place after the cross-border auction) and the GB day-ahead auction (a similar process, again after the cross-border auction, although the limit is expressed in GBP). This is most likely due to issues of convenience and to prevent creating perverse incentives to trade in one of the markets as opposed to another.

Option 1: Eliminate all price caps

This option would see a prohibition on all upper price restrictions in the wholesale market, in all timeframes. It would mean that prices would be able to reach VoLL. It would also involve a prohibition on any technical price limits imposed by power exchanges.

Option 2: Create obligation to set price caps, where they exist, at VoLL

This option would require that, where caps exist, they shall be no lower than VoLL in all market timeframes. This would be coupled with a requirement that Member States establish VoLL. This option would be compatible with a technical limit imposed by power exchanges, but would include a trigger to raise such limits in order to prevent them constraining acurate price formation coupled with a date by which the maximum must not be below VoLL. It would also make clear that, once at VoLL, the value need not be harmonised.

4.1.5. *Comparison of the options*

As detailed above, allowing prices to reflect scarcity, and investors having confidence that this will be allowed to happen, is key to stimulating investment in a more flexible system.

The options must, therefore, be assessed in this context i.e. those options which would prevent scarcity prices forming and, in particular, reflecting the true scarcity in terms of willingness to pay for energy, would not be compatible with the objective of creating an energy market that is able to face future challenges and stimulate the right investments.

The 'do nothing' option would not be consistent with the set objectives – even though harmonised maximum clearing prices would be implemented, these only have to 'take into account' the value of lost load and there would be no way to provide confidence that prices could indeed reach values which reflect scarcity. It would allow for price caps to continue existing within Member States. Whilst in practice, for most Member States, prices have not been constrained by existing caps (there have been no instances yet where they have hit the 3000 euros mark), this is not set to remain the case forever.

Doing nothing, or relying on voluntary cooperation at the Member State level, would not provide investors with any confidence that restrictions would be removed (or raised) in the event they were hit and the default position is that they would remain in place. It therefore has to be assumed that such an option would shave off the peaks in pricing. Whilst the CACM Guideline contains a reference to VoLL, 'take into account' is not enforceable.

Option 1 – to eliminate any price caps - would be the option most in line with this specific objective, in that it would allow prices to rise to any level, determined by supply and demand fundamentals. Making a strict, EU-level prohibition may provide investors with confidence that Member States would not intervene to keep wholesale prices low for political reasons – e.g. because of a negative perception of the impacts of peaking prices on consumers. This option, however, entails risks. In particular, it would prevent any limits being used in the market coupling system or by power exchanges. This could have technical impact on the operation of the systems used to run the markets and may influence the amount of collateral that market parties are required to post. Market parties are generally required to provide cash or credit to cover their potential exposure. Without limits in the clearing price, this could become more expensive or their credit more restrictive (e.g. on how much they can trade), as the potential exposure would be higher. Further, it could prevent the use of any explict price-based measure to detect errors in bidding.

Option 2 would allow for the use of limits to exist in the context of trading on the power exchanges and only in relation to maximum and minimum clearing prices developed in accordance with the CACM Guideline. In order to prevent such limits restricting accurate price formation, the option would also introduce a specific requirement that they be raised when a trigger point is reached coupled with a requirement that they be set at the value of lost load within a certain timeframe. The option would also prohibit Member States from introducing legal caps on the wholesale price unless this reflects a calculation of the value of lost load.

The advantage of this approach is that it would still allow for technical limits to be introduced by power exchanges, but would not constrain price formation and would give investors a clear signal that Member State authorities cannot step in artificially dampen prices. The disadvantage as compared to Option 1 is that, in order for such limits to continue to exist and to be effective, there may need to be a time lag between the trigger and the limit being raised. This would need to be as short as possible so not to prevent prices from rising.

A difficulty with this option is the complexity of establishing VoLL. It will change depending on the circumstances and the user and so one value will only ever be an estimation.

This option would also be bundled with a requirement placed on Member States to avoid and, where possible, eliminate any implicit price caps so not to disincentives the offering of high prices by market participants.

The benefits of better price signals and further articulated as part of the wider option to address uncertainty on future investments (Problem Area II, which includes policies on locational signals, scarcity pricing and price caps, resource adequacy planning and capacity mechanisms) in Section 6.2.2.

4.1.6. *Subsidiarity*

Given that the EU energy system is highly integrated, prices in one country can have a significant effect on prices in another. Further, if there are significant differences between countries on the level to which wholesale prices can rise, then energy may flow in the wrong direction during times of system stress. A coordinated and harmonised approach is, therefore, necessary.

This topic is, to an extent, already covered under the CACM Guideline – which notably requires the setting of harmonised maximum clearing prices which take into account the value of lost load.

Differences in national approaches could create significant distortions in the market and prevent the most cost-effective supply of electricity. It could also distort investment signals, for example those countries who have a higher cap would potentially attract more investment thnt those with a lower cap.

EU action is therefore necessary to ensure a common approach is taken which minimises distortions in the operation of markets between Member States.

4.1.7. *Stakeholders' opinions*

From the Market Design consultation, a large majority of stakeholders agreed that scarcity pricing is an important element in the future market design. It is perceived, along with current development of hedging products, as a way to enhance competitiveness. While single answers point at risks of more volatile pricing and price peaks (e.g. political acceptance, abuse of market power), others stress that those respective risks can be avoided (e.g. by hedging against volatility).

Many submissions to the consultation highlighted the link between scarcity pricing and incentives for investments/capacity remuneration mechanisms, as well as the crucial role of scarcity pricing for kick-starting demand response at industrial and household level.

Key stakeholder comments included:

- *"…energy prices that reflect market fundamentals, including scarcity in terms of time and location, are an important ingredient of the electricity market design. Undistorted prices (without regulatory intervention) should thus trigger optimal dispatch and signal the need for investments/divestments… Price caps and other interventions in the market hindering the appearance of scarcity prices should be removed."* Eurelectric
- *"…we need to better valorize flexibility. Prices reflecting scarcity are crucial in this context and should therefore be a key priority of the market reform… Prices better reflecting scarcity will be more volatile and might be higher than today during some periods of the day (assuming the end of price caps). Rather than a challenge, this represents an opportunity as it will unlock new strategies to hedge against risks on the wholesale market while triggering dynamic pricing offers on the retail side."* SolarPower Europe.
- *"In principle, electricity prices should reflect actual scarcity so that the most cost-efficient flexibility options on the supply and the demand side as well as the most efficient storage solutions are employed. Prices should also reflect the scarcity of transmission capacities within and across market borders"* EUROCHAMBERS

- *"In order to provide correct price signals for new investments (both generation and consumption), and to provide security of supply, prices which reflect actual scarcity are an important ingredient in the future market design."* BusinessEurope
- *"Citizens Advice supports efforts to move to market structures that more accurately reflect scarcity. This is an important way of conveying price signals reflecting the genuine value of consumption and production, at different times and in different locations."* Citizens Advice
- *"…energy prices should effectively reflect both temporal scarcity and surplus in order to adequately reward flexibility. Such an approach to energy pricing would better facilitate the investments required to address the European energy trilemma of sustainability, security of supplies, and competitiveness."* WWF

Further, in a position paper, Wind Europe state that "[i]*t is important that market prices are undistorted and allowed to move freely without caps. Transparent market prices must be in place in all time horizons, i.e. forward, day-ahead, intraday and real time, and also used for settlement of remaining imbalances. This will help to incentivise and reward the provision of flexibility services. Policy makers should be aware that price spikes are needed to trigger the right scarcity signals on both the supply and demand side; investment decisions based on a certain expectation of price spikes will only be made if there is enough trust by investors that politicians will not interfere and introduce price caps. "* [3]

The March 2016 Florence Forum made the following relevant conclusion:

"The Forum acknowledges the significant progress being made on the integration of cross-border markets in the intraday and day-ahead timeframes, and considers that market coupling should be the foundation for such markets. Nevertheless, the Forum recognises that barriers may continue to exist to the creation of prices that reflect scarcity and invites the Commission, as part of the energy market design initiative, to identify measures needed to overcome such barriers. In doing so, it requests the Commission take proper account of technical constraints that may exist."

[3] https://windeurope.org/fileadmin/files/library/publications/position-papers/EWEA-Position-Paper-Market-Design.pdf

4.2. Improving locational price signals

4.2.1. *Summary Table*

Objective: The objective is to have in place a robust process for deciding on the structure of locational price signals for investment and dispatch decisions in the EU electricity wholesale market.

	Option 0	**Option 1**	**Option 2**	**Option 3**
Description	Business as Usual – decision on bidding zone configuration left to the arrangements defined under the CACM Guideline or voluntary cooperation, which has, to date, retained the *status quo*.	Move to a nodal pricing system	Introduce locational signals by new means, i.e. through transmission tariffs	Improve currently existing the CACM Guideline procedure for reviewing bidding zones and introducing supranational decision-making, e.g. through ACER. This would be coupled with a strengthened requirement to avoid the reduction of cross-zonal capcity in order to resolve internal congestions.
Pros	Approach already agreed.	Theoretically, nodal pricing is the most optimal pricing system for electricity markets and networks.	Would unlock alternative means to provide locational signals for investment and dispatch decisions.	This improvement will render revisions of bidding zones a more technical decision. It will also increase the available cross-zonal capacity.
Cons	Risks maintenance of the *status quo*, and therefore misses the opportunity to address issues in the internal market.	Nodal pricing implies a complete, fundamental overhaul of current grid management and electricity trading arrangements with very substantial transition costs.	Incentives would be not be the result of market signals (value of electricity) but cost components set by regulatory intervention of a potentially highly political nature. Does not address the underlying difficulty of introducing locational price zones, namely the difficulties to arrive at decisions that reflect congestion instead of political borders.	Does not address a situation where the results of the bidding zone review are sub-optimal. I.e. this option only covers procedural issues.

Most suitable option(s): Option 3 – this option will rely on a pre-established process but improve the decision-making so that decisions take into account cross-border impact of bidding zone configuration. Other options – e.g. tofundementally change how locational signals are provided, would be dispropritionate.

4.2.2. *Description of the baseline*

The internal energy market is based on the concept of bidding zones, which are defined as *"the largest geographical area within which market participants are able to exchange energy without capacity allocation."*[4] They are effectively market areas within which energy is considered to be able to flow freely and within which, therefore, there will be a single wholesale price for any given market timeframe.

Currently, bidding zones are based on national borders, although there are some exceptions[5].

Figure 1, Curent bidding zone configuration

Source: Ofgem, 2014

The wholesale price will be the same in one part of France as it is in another, the same in one part of Spain as it is another part of Spain, the same in Germany as it is in Luxembourg and Austria, and so on. The wholesale price in Italy may be different in different parts, as it may be in Sweden and Norway.

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4 Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets

5 There is currently one German-Austrian-Luxembourg bidding zone, and Italy, Sweden and Norway are split into several zones.

This is critical, as the wholesale price is a crucial part of determining when and where people invest (and where there are no other revenue streams such as capacity mechanisms, the only basis). Higher prices in one area will in theory attract investment into that area over and above somewhere with lower prices. This locational signal in the energy price will not exist within a bidding zone, and so will not encourage investment in one part as compared to another and, in the case where bidding zone boundaries are based on Member State borders, within one part of a Member State compared to another. This is despite the fact that there may be bottlenecks within that Member State that prevent the free flow of energy from one part to another and, hence, could create a greater need for investment in certain geographical areas.

Further, wholesale energy prices will determine when generating plants dispatch and, to a lesser degree (due to relative inelasticity in the demand-side) when load consumes energy. i.e. where the price is higher than a generator's short-run marginal cost, bar any external factors, they will run. If there are significant congestions within a bidding zone, and the price is influenced by demand behind such congestion, generators on the other side may still dispatch despite limited ability to transport the energy to the demand. This can result in the so-called 'loop flow' phenomenon whereby energy will flow around the congestions through another zone, against market price signals. These flows, as they have not been scheduled, can have significant implications. More specifically, they can reduce the amount of cross-border capacity made available to the market for trade and result in costly remedial actions, for example the need to redispatch (the reduction in the amount of power injected on one side of the congestion and, simultaneously, an equivalent increase in the amount injected on the other side). As an example, in 2015 the total cost for redispatching within the DE-AT-LU bidding zone was approximately 930 million euros[6]. Overall, the total welfare loss due to loop flows was estimated to be around 450 million euros in 2014[7].

An improved configuration of bidding zones, one which takes account of structural congestions within the European grid, would mitigate many of these issues, as it would improve the locational price signals. In particular, in the short-term it would affect how and where energy is dispatched and, for the longer-term, will improve the price signals on where to locate new generation investments. Clearly investment in transmission capacity is also critical, notably within a bidding zone so that energy can better flow from one area to another. However, the bidding zone structure itself may not provide strong signals for such investment; as Ofgem point out in its Bidding Zone Literature Review (2014)[8], impact on investment may be muted by practical consideration, for example, due to economies of scale, uncertainties about future generation investment, and difficulty in centralising charges or reliability and quality of service.

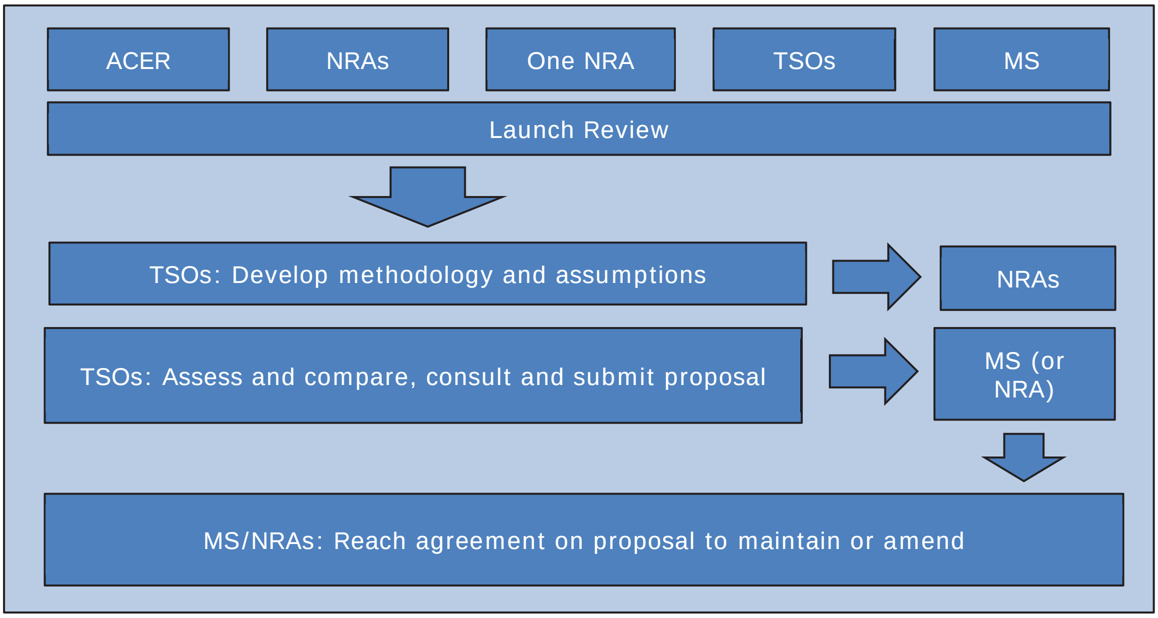
6 ENTSO-E Transparency Platform, at https://transparency.entsoe.eu/

7 "*Market Monitoring Report 2014*" (2015) ACER – social welfare losses for both unscheduled flows and unscheduled allocated flows.

8 https://www.ofgem.gov.uk/sites/default/files/docs/2014/10/fta_bidding_zone_configuration_literature_review_1.pdf

The precise definition of bidding zones, and realising maximum benefit from it, is complex and highly technical, and there are a number of variables which must be considered. Therefore, a review process, to be undertaken by TSOs, has been formalised in legislation under the CACM Guideline[9]. More specifically, once a review is launched[10], TSOs are to review the existing bidding zone configuration and alternative bidding zone configurations, and must submit this to Member States or, where so determined by a Member State, NRAs for a decision on whether to amend or maintain the zones. Figure 2 below provides a summary of this process.

Figure 2, simplified flow chart of bidding zone review process under the CACM Guideline



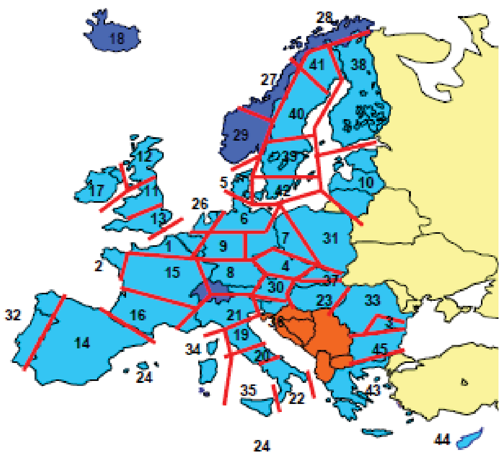
When undertaking a review, TSOs must consider issues relating to network security, market efficiency, including any increase or decrease in economic efficiency of changes, and stability and robustness of bidding zones.

A number of authors have already suggested alternative configurations, for example as shown in figure 3.

9 In practice, work has already started on this.

10 Which can be done by ACER, NRAs, Member States or TSOs, depending on specific criteria – Article 32

Figure 3, possible alternative configuration,



Bidding zones for Europe			
1	Belgie & France du Nord	23	Magyar
2	Bretagne	24	Mallorca
3	București	25	Malta
4	Czech	26	Nederland
5	Danmark Vest	27	Norge Mellan
6	Deutschland Nord	28	Norge Nord
7	Deutschland Ost & Śląsk	29	Norge Syd
8	Deutschland Süd, Alsace, Lorraine, Schweiz, Tyrol & Vorarlberg	30	Österreich
		31	Polska centralna
9	Deutschland West & Letzeburg	32	Portugal & Galicia
10	Eesti, Latvija & Lietuva	33	Romania
11	England Middle	34	Sardegna & Corse
12	England North & Scotland	35	Sicilia
13	England South	36	Slovenija
14	España	37	Slovensko
15	France Centre & Suisse	38	Suomi
16	France Sud	39	Sverige Mellan
17	Ireland	40	Sverige Norbotten
18	Island	41	Sverige Nord
19	Italia Centro Nord	42	Sverige Syd & Danmark Ost
20	Italia Centro Sud	43	Ελλαδα
21	Italia Nord, Svizzera & Cote d'Azur	44	Κύπρος
22	Italia Sud	45	България

Source: Supponen, Influence of National and Company Interests on European Electricity Transmission Investments, 2011

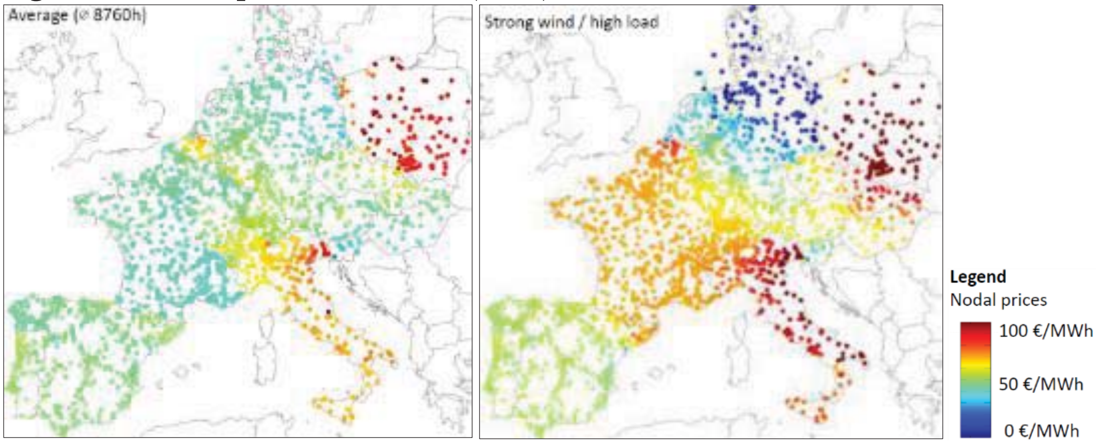
However, as pointed out by Supponen (2011), even price zones which reflect the most congested parts of the European grid, will not provide as efficient price signals as a system which is based on a more granular system, such as that of nodal pricing. Nodal pricing is a method of determining prices in which market clearing prices are calculated for a number of locations on the transmission grid called 'nodes'. These nodes would be determined based on the most congested points in the system. The price at each node represents the locational value of energy, which includes the cost of the energy and the cost of delivering it[11]. This model is used in much of North America. For example, the PJM's system includes over 10 000 price nodes across 20 transmission control zones, with trading available at nodes, at aggregates of several nodes, at 12 hubs consisting of hundreds of nodes each, and at 17 import and export external interfaces. The IEA conclude that *"This nodal pricing system facilitates adjustments to dispatch in the real-time market, efficient use of variable resources and demand-side response, and limits to market power by individual generators"*[12].

In 2014, Breuer simulated the potential price differences based on a nodal system in Europe, comparing average across the year with times of strong wind and high load in continental Europe.

[11] Phillips, Nodal Pricing Basics, Independent Electricity Market Operator, available at http://www.ieso.ca/imoweb/pubs/consult/mep/LMP_NodalBasics_2004jan14.pdf

[12] Repowering markets

Figure 4 – Nodal prices, base case (2016)



Source: Breuer, Optimised bidding area delineations and their evaluation in the European Electricity System, Brussels, April 2014 – Nodal prices (base case) 2016

As can be seen from the above, there could be significant changes in prices in a nodal system compared to average prices across Europe on windy days with high demand. Such a picture serves to illustrate what the prices should be if transmission capacity were fully taken into account. This does not cluster around the current bidding zone configuration as shown above and suggests inaccuracy of price formation in the current setup. It is also far from clear just from the above how this could be best grouped into a bidding zone structure, and several possibilities exist just from this one scenario. The complexity could be further increased when looking at alternative scenarios (e.g. high wind/low demand, etc.).

It is therefore concluded that it is correct to rely on a technical analysis where the costs, benefits and practical considerations (including those listed in the CACM Guideline) will be considered – this is much more likely to result in a more optimal configuration than the one currently seen. The issue at stake, therefore, is how to make any change based on the outcome of the review pre-establishing under the CACM Guideline, or whether to move to a wholly different arrangement for locational signals such as the mandatory introduction of locational elements in transmission changes or moving to a nodal system

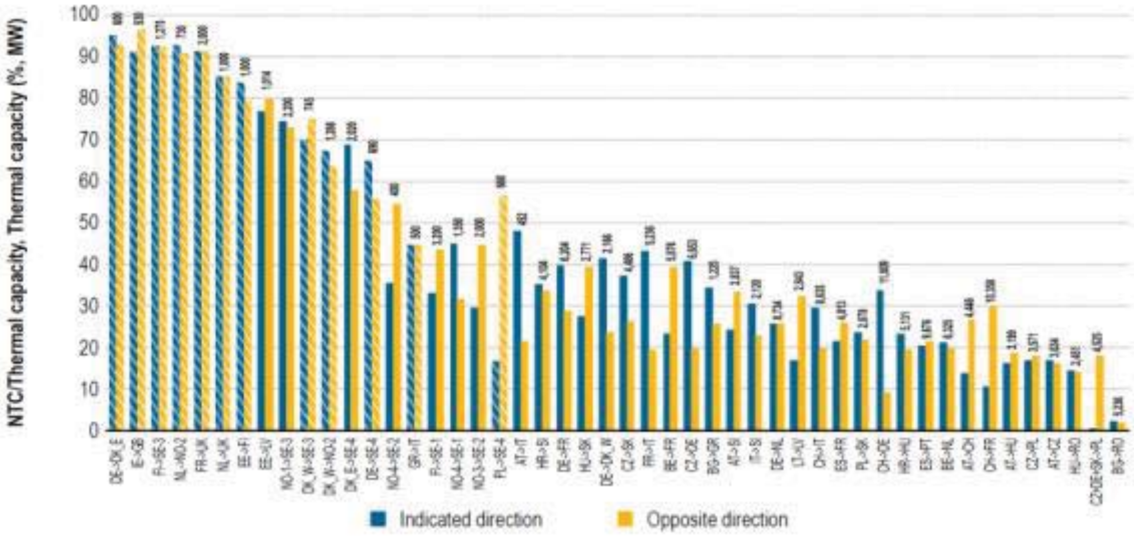
Cross-zonal capacity calculation

With a, theoretical, 'perfect' bidding zone configuration, the only congestion would be on a bidding zone border. Therefore, there would be no internal constraints that would cause reductions in cross-border capacity. However, even if and when a configuration is implemented that better reflects structural congestion, there will still be internal congestion. The Electricity Regulation states that:

"TSOs shall not limit interconnection capacity in order to solve congestion inside their own control area, save for the abovementioned reasons and reasons of operational security"[13]

There is, however, evidence that cross-zonal (interconnection) capacity is indeed being limited in order to deal with internal issues. In its Market Monitoring Report, ACER analysed the ratio between thermal capacity (the theoretical maximum capacity) of interconnectors and the capacity offered for trade (with Net Available Capacity – NTC Capacity). The results showed that the ratios varied significantly and that on a number of borders the NTC was significantly below the thermal capacity.

Figure 5 – Ratio between available NRC and aggregated thermal capacity of interconnectors – 2014 (%, MW),



Source: ACER/CEER Market Monitoring Report 2015.

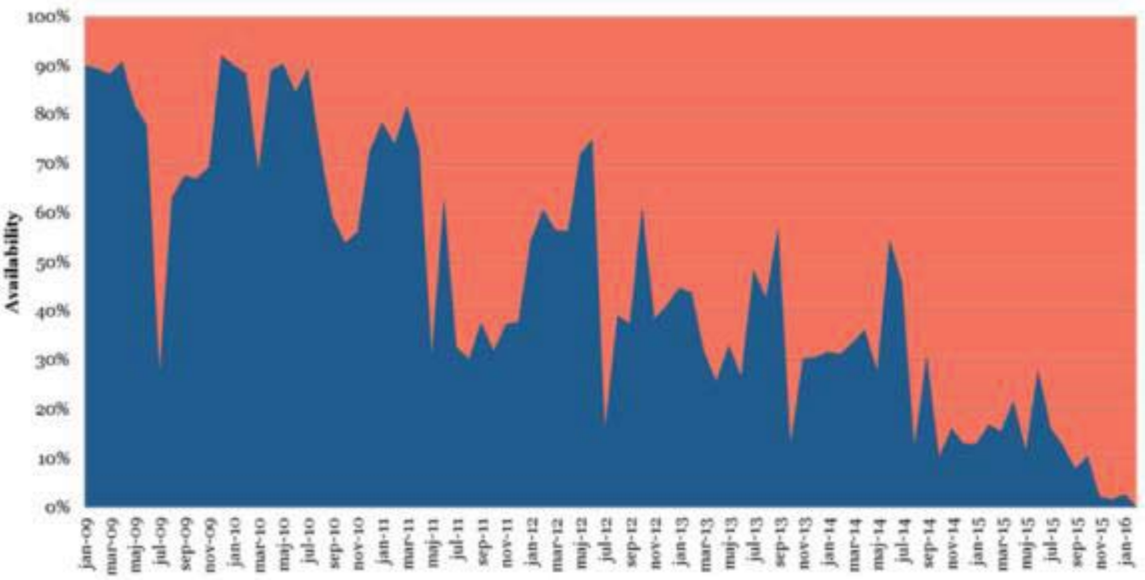
ACER concluded that "these results indicate that on the borders on the right side of the figure either the internal congestions are shifted to the border, or those borders are affected by a significant amount of unscheduled flows."

Regardless of the reason, the impact of this is the reduction of cross-border trade and has resulted in the need to curtail capacity the other side of the border. The German-Danish border provides an example of the sorts of impacts this can have. The below graph shows the average interconnection capacity was 250MW on DK1-DE in 2015, 15% of the maximum capacity. An investigation for the Danish TSO energinet.dk and the relevant

[13] Annex I section 1.7

German TSO TenneT found that a minimum capacity of 1.000 MW will bring a social economic benefit to the region of approximately 40 million euros per annum[14].

Figure 6: Monthly average NTC as part of total transfer capacity (2009-2016).



Source: energinet.dk as reported by the Danish Energy Regulatory Authority[15]

4.2.3. *Deficiencies of the current legislation*

The most relevant legislation is the Electricity Regulation, which contains a detailed Annex on congestion management. However, it does not define bidding zones. In Section 1.7 it states that *"when defining appropriate network areas in and between which congestion management is to apply, TSOs shall be guided by the principles of cost-effectiveness and minimisation of negative impacts on the internal market in electricity."*

More detail is provided under the CACM Guideline, which contains a detailed approach to reviewing and defining prices zones (Articles 32 through 34), as detailed above. Following TSOs' review and proposals Member States are required to "reach an agreement on the proposal to maintain or amend the bidding zone configuration."

This approach lends itself to the maintenance of the *status quo* as there are likely to be competing interests at stake. In particular, some Member States are unlikely to want to amend bidding zones where it would create price differentials within their borders; it is sometimes considered to be right for all consumers to pay the same price within a Member State, and for all producers to receive the same price. The current legislation does not, therefore, provide for the socially optimal solution to be agreed.

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[14] Investigation of welfare effects of increasing cross-border capacities on the DK1-DE interconnector. Institute for Power Systems and Power Economics. RWTH Aachen University. June 2014. Study commissioned by TenneT and Energinet.dk.

[15] "*STUDY ON CAPACITY REDUCTIONS ON THE GERMAN – WESTERN DANISH BORDER (DE-DK1) (Tender for Offers)*" - http://f.industry-supply.dk/2bjt3mw1t748a8fa.pdf

With regards to cross-zonal capacity, the current terms of the Electricity Regulation are unclear and allow for different interpretations and application.

The Evaluation Report concludes that *"the Third Package clearly lacks rules for the development and functioning of short markets as well as rules that would enable the development of peak prices reflecting actual scarcity in terms of time* and location,*"* and that *"given the economic importance (and distributive effects) of the decisions TSOs have to agree on, experience has shown that voluntary cooperation between TSOs was not able to overcome the problems that block progress in the internal electricity market (e.g. definition of fair bidding zones, effective cross-border curtailments)"*

4.2.4. <u>*Presentation of the options*</u>

Option 0**:** BAU and stronger enforcement

This option would entail relying on existing legislation to improve the configuration of bidding zones. The likelihood of seeing any meaningful change as a result of this process is minimal. Existing provisions under the Electricity Regulation are arguably not sufficiently clear and robust to enforce a structure which reflects systematic constraints in the interconnected system. The provisions of the CACM Guideline do not provide for a clear decision-making process which provided any degree of certainty that the change will be made, but rather it is left to individual Member States to make the decisions even though these decisions have significant cross-border impacts.

Voluntary cooperation

As highlighted above, the evidence suggests that voluntary cooperation will not result in progress in this area, as there has been to date already significant opportunity to effect the necessary changes voluntarily.

Option 1: Move to a nodal-pricing system

A nodal pricing system would be the most granular way of determining location-based energy prices. In theory, this would eliminate the need for remedial actions by the TSO to alleviate congestion as the price of energy would determine exactly where it should be dispatched from. It would also create more accurate investment signals in new generation and infrastructure – in the case of the former in areas with higher prices, reflecting more scarcity.

Moving to a nodal pricing system would require a fundamental change in the way European energy markets are structured – current arrangements for cross-border trading (market coupling) would need to be redeveloped, implying significant IT and procedural changes. It would also be a significant change for market participants. The cost impact of this would, in the short-term, likely out weight the benefits.

Option 2**:** Introduce locational signals through other means

It is possible to introduce signals for investment and/or dispatch through other means than a market-based energy price. The main alternative method is through transmission tariffs – i.e. charging generators less in areas where more capacity and energy is required, and more where it is not. This can provide effective signals. It would mean a fundamental change to the tariffs structure as around half (15) of Member States do not apply transmission tariffs to generation. Further, this would not necessarily affect dispatch as, if

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Improving locational price signals

charges are based on capacity, it becomes part of a generators fixed cost and will not affect when they generate. Moving to 'energy-based' charges could add distortions into the market as it would be very difficult to engineer this in a way which reflected the congestion and the dynamic-nature of production. Indeed, ACER has recommended the removal of energy based transmission charging on generators.

Option 3**:** Improve bidding zone review and decision-making process

As mentioned above, a review process is already detailed as part of the CACM Guideline. There is a requirement to review both existing and possible alternative configurations, the latter of which is triggered by specific circumstances. This option would see a strengthening of the decision-making process as a result of the review, in particular to ensure that the cross-border impacts of bidding zone configurations are appropriately taken into account. This would be achieved explicitly clarifying existing requirements for price zone borders to be based on congestion and not Member State borders. Procedurally, more powers would be given to EU institutions to decide on price zone configuration following the review. There could also be some amendments to the review process itself to ensure that it can show the optimal solution.

The option would be coupled with strengthened legal provision that make clearer the allowed derogations to the overriding rule that cross-zonal capacity must not be limited to solve internal congestion, and make any derrogation subject to regualtory oversight.

4.2.5. *Comparison of the options*

Maintaining the current system of review, and leaving the final decision-making in the hands of national authorities, would be the simplest option and the one which would yield the least disruption. However, as highlighted above, the process lends itself to maintenance of the *status quo* as decisions will be made on an individual, rather than collective basis. Difficulties have already arisen in the process (relating to some ambiguities in the current legislation). The benefits of price zone boundaries, reflecting structural congestions would not be seen, or would only partially be realised, if there is no coordinated decision. These have been estimated to be between 300-400 million euros per annum[16] to around 800 million euros[17].

The second option (Option 1), to move to a nodal pricing system, would be the most complex to implement. It would involve a complete redesign of the current system. It would involve fundamentally moving away from the current market setup and would significant changes to trading arrangements. By way of example, the current approach for coupling national markets would likely need to change significantly, which would involve large changes to IT and practices of traders, TSOs, power exchanges, suppliers and generators. The costs of change would be significant. Burstedde, in an analysis of a number of central European countries[18] found that there would be overall savings in the

[16] Bauer, ibid.
[17] Duthaler, C. (2012): "*A network and performance based zonal configuration algorithm for electricity systems"*, Dissertation, EPFL, Lausanne (Switzerland)
[18] Comprising of AT, CH, DE, NL, VE and FR

total cost of electricy supply from a nodal model, compared to a model based on bidding zones around Member State borders, of around 940 million euros, mostly due to redispatch costs. However, she also concluded that "the increase in overall system costs which results from aggregating nodes into zones remains negligible in relative terms" and that there would be savings from any move from nationally-based bidding zone borders[19].

The assessment of a nodal model will also form part of the review of bidding zones structures by TSOs – it is therefore considered premature to conclude that Europe should move to such a model before this review has concluded; the process will allow a proper assessment of the different options and a decision can be taken on the basis of this.

Option 2 would require the introduction of administered locational signals. It is very unclear what the costs and benefits of this approach would be, given that it would depend on the prices set. If it were done on a capacity basis it would only impact the investment signals, and not dispatch signals. If it were done on an energy basis, then it could add significant distortions, e.g. by changing the merit order between different plants. This would be counter-productive and erode the benefits from the market design initiative.

Option 3 builds on the system already established in the EU, as well as processes already developed as part of the CACM Guideline. However, by moving to a more coordinated decision-making process, one which does not prejudice the assessment of the benefits and the costs of potential alternatives by TSOs, the likelihood that decisions are taken which reflect the cross-border impacts of the bidding zone structure is greatly increased. A more appropriately defined bidding zone structure could reduce the need for remedial actions, such as redispatch, reduce unscheduled flows in the form of loop flows, and improve signals for investment. Even so, an improved bidding zone structure would not eliminate internal congestion. Strengthened provisions in the Electricity Regulation to provide very clear rules on when cross-border capacity can be limited will help alleviate the economic impacts of this happening in order to address internal issues.

The benefits of better locational signals are further articulated as part of the wider option to address uncertainty on future investments (Problem Area II, which includes policies on scarcity pricing and price caps, resource adequacy planning and capacity mechanisms) in Section 6.2.2.

4.2.6. *Subsidiarity*

Networks in the EU energy market are highly meshed and therefore energy trading in one part has a significant part on another part. There are, however, naturally bottlenecks in the system that prevent unhindered flow of energy – termed congestion. These do not necessarily (and, in the case of the continental and Nordic synchronous areas) follow Member State borders.

The Third Package already contains provisions relating to congestion management, requiring procedures to be put in place, which is further elaborated by the CACM

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[19] Around 280 million euros in the case of moving to 9 zones.

Guideline. It is important to have a harmonised approach to the management congestion in order to manage it cost-effectively across the market and allow for maximum cross-border trading.

Markets are split based on price zones, where the wholesale price is the same for each given timeframe. These provide locational signals for dispatch and investment.

Whilst the Third Package has achieved much, further action is needed at the EU-level – price zones based on Member State borders do not reflect the actual locational need for investment or demand for energy in a particular location. More coordinated action is therefore necessary to direct dispatch of energy and investment in infrastructure based on where it is needed and will provide most benefit to the EU interconnected system as a whole. This will become increasingly important with more and more variable sources of generation coming online over the coming years.

Action is already underway reviewing the structure of price zones in the EU. However, the decision-making is still left at the national level, which lends itself to maintenance of the *status quo*, which can have negative cross-border impacts (such as unscheduled flows of energy from one country to another as a result of inefficient price signals).

4.2.7. *Stakeholders' opinions*

A large number of respondents to the Energy Market Design consultation agreed that energy prices should not only relate to time, but also locational differences in scarcity (e.g. by meaningful price zones or locational transmission pricing). While some stakeholders criticised the current price zone practice for not reflecting actual scarcity and congestions within bidding zones, leading to missing investment signals for generation, new grid connections and to limitations of cross-border flows, others recalled the complexity of prices zone changes and argued that large price zones would increase liquidity.

WindEurope (formally EWEA) commented that "[w]*holesale electricity prices reflecting scarcity and physical constraints, including transmission capacity, are desirable in a fully functional electricity market. This is already expressed in the present zonal pricing model inside bidding zones and between bidding zones where price differentials signal the need for transmission investments."*

In their joint response to the consultation, ACER/CEER stated that "[p]*rices reflecting scarcity (both in terms of time and location) of generation resources in each bidding zone of organised markets in the different timeframes (day-ahead, intraday and balancing) should become a key ingredient of the future market design."*

EURELECTRIC *"generally favours larger bidding zones as they present more advantages for the functioning of the market and its liquidity, however bidding zone configuration should duly take into account the grid capacity. Zones should respect structural bottlenecks that do not necessarily correspond to national borders."*

The European Association for Storage of Energy (EASE) said that "[p]*rices need to reflect the physical limitations of the grid in order to deliver optimal locational signals for investment, consumption and production."*

Another is example is that of Norderegi, who view is that "[f]*undamentally, the borders between Bidding Zones should be based on the physical characteristics of the power* *system. Bidding Zones should be aligned with where structural constraints occur. Leading principle is that cross border trade must not be restricted. Moving internal national transmission bottlenecks to national borders must not be used as a congestion management method."*

On the other hand, some stakeholders highlight risks to changes in price zone configuration. For example, the European Energy Exchange (EEX) states that *"The development towards large, cross-border bidding zones supports the efficiency of the power system by integrating markets. Supply and demand can be brought together more efficiently. The prerequisite for this is grid expansion. Delayed or insufficient grid expansion even in a national context has a negative impact on the market as a whole, as is currently seen in the discussion of splitting the German/Austrian bidding zone. Such a decision would be a huge step back in the creation of the internal market, splitting Europe's most liquid bidding zone, decreasing the possibilities of risk mitigation and eventually causing higher energy prices for consumers."*With regards to congestion management, there have been significant concerns raised by industry about the practice of limiting cross-border capacity to deal with internal congestion. For example, Nordenergi have said, in a public letter to the European Commission, that the *"principle that congestion needs to be managed where it occurs must be maintained as the governing rule in an internal market, and this principle does not allow for congestion to be moved to national borders in the extent and in the non-transparent manner that seems to be the case on the mentioned Nordic borders"* and that *"besides the continuous welfare losses due to curtailments of cross-border capacities, there are in addition severe long-term negative effects through inefficient investment signals to both generators, consumers and TSOs."*

4.3. Minimise investment and dispatch distortions due to transmission tariff structures

4.3.1. *Summary table*

Objective: to minimise distortions on investment and dispatch patterns created by different transmission tariffs regimes.				
	Option 0: Business as usual	**Option 1: Restrict charges on producers (G-charges)**	**Option 2: Set clearer principles for transmission charges**	**Option 3: Harmonisation transmission tariffs**
Description	This option would see the *status quo* maintained, and transmission tariffs set according to the requirements under Directive 72 and the ITC regulation. Stronger enforcement and voluntary cooperation: There is no stronger enforcement action to be taken that would alone address the objective. Voluntary cooperation would, in part, be undertaken as part of implementation of Option 2.	This option could see the prohibition of transmission charges being levied on generators based on the amount of energy they generate (energy-based G-charges)	This option would see a requirement on ACER to develop more concrete principles on the setting of transmission tariffs, along with an elaboration of exiting provisions in the electricity regulation where appropriate.	Full harmonisation of transmission tariffs.
Pros	Pros: Minimal change; likely to receive some support for not taking any action in the short-term.	Eliminating energy-based G-charges would serve to limit distortionary effects on dispatch of generation caused by transmission tariffs. Social welfare benefits of approximately EUR 8 million per year. Would impact a minority of Member States (6-8 depending on design).	Provides an opportunity to move in the right direction whilst not risking taking the wrong decisions or introducing inefficiencies because of unknowns; consistent with a phased-approach; could eliminate any potential distortions without the need to mandate particular solutions; consistent with the introduction of legally binding provisions in the future, e.g. through implementing legislation.	Minimises distortion between Member States on both investment and dispatch; creates a level-playing field.
Cons	In the longer-term, likely to be a drive to do more and maintaining the *status quo* unlikely to be attractive; risks of continued divergence in national approaches.	Social welfare benefits relatively small – could be outweighed by transitional costs in the early years. Can be considered 'incomplete' as a number of other design elements of transmission tariffs contribute to distortionary effects.	Still leaves the door open for variation in national approaches; will not resolve all potential issues.	Unlikely to a proportionate response to the issues at this stage; given the technicalities involved, it could be more appropriate to introduce such measures as implementing legislation in the future.
Most suitable option(s): Option 2 – aside from some high-level requirements, given the complexity of transmission charges, the precise modalities should be set-out as part of implementing legislation in the future if and when appropriate. The value in Option 2 will be to set the path for the longer-term.				

4.3.2. *Description of the baseline*

Tariffs are charged on demand and/or production in order to recover the costs associated with building, maintaining and operating transmission and distribution infrastructure. They can be used merely as a cost recovery tool, but also as a means to incentivise investments and behaviours. They also have the potential to have distortionary effects. In this annex, the focus is on the design of transmission tariffs, with distribution tariffs discussed further in Annex 3.3. However, there are potentially important interactions, which are touched on further below.

There are a number of decisions that regulatory authorities can take on the design of tariffs. These are summarised below:

Figure 1 – building blocks of transmission tariffs

Building block:	Notes:
Generation / load	Are transmission tariffs levied on generation or load, or both? Do transmission tariffs apply to embedded generation?
Capacity vs. commodity	Are tariffs levied on a MW (capacity) basis or MWh production/consumption basis?
Locational charging?	Are transmission tariffs locationally differentiated (with locational signals) or uniform?
Zonal vs. nodal?	If transmission tariffs are locational, do tariffs differ by node or do they differ by zone?
Time of day signals?	Do transmission tariffs provide economic incentives for time of use of the transmission network?
Types of cost	What types of costs does the transmission tariff recover?
Cost recovery	Are tariffs based on short or long term costs? Are tariffs based on marginal or average costs? How is full cost recovery achieved?
Connection regime	Are use of system charging arrangements accompanied by shallow or deep connection charging arrangements?

Source: Cambridge Economic Policy Associates Ltd for ACER.

The Third Package, and more specifically the Electricity Directive and Electricity Regulation, contain specific provisions for the charging of transmission tariffs. Requirements under the Directive include that tariffs, or the methodologies for calculating them, must be fixed or approved by NRAs in accordance with transparent criteria[20] and sufficiently in advance of their entry into force[21].

Article 14 of the Electricity Regulation provides further requirements, which include:

- that "[c]*harges applied by network operators for access to networks shall be transparent, take into account the need for network security and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and are applied in a non-discriminatory manner;"* and
- that, "[w]*here appropriate, the level of the tariffs applied to producers and/or consumers shall provide locational signals at Community level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure."*

More specific requirements are provided for under the inter-transmission system operator compensation mechanism ("**ITC"**) regulation[22]. This regulation sets down limits on the average annual transmission charges that can be applied in each Member States to electricity producers[23]. The regulation also required ACER to provide an opinion to the Commission regarding the appropriateness of the range of charges, which it did on 15th April 2014.

In the opinion, ACER stated that it deemed it important that charges on generators ("**G-charges"**) are "*cost-reflective, applied appropriately and efficiently and, to the extent possible, in a harmonised way across Europe."* It recommended that: G-charges based on energy produced (energy-based) should not be used to recover infrastructure costs; energy-based G-charges should be set at 0 euros/MWh, except where they are used for recovering the costs of system losses or costs relating to ancillary services. They concluded, however, that it was unnecessary to propose restrictions on charges based on connected capacity of the generation (what they term power-based charges) or fixed (lump sum) charges.

However, prior to this opinion, a report by Frontier Economics for Energy Norway, published in May 2013[24], concluded that the potential for welfare loss is significant, with effects on investment more significant than operational decisions, and strong welfare losses result from a lack of harmonisation.

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20 Art 37(1)(a)

21 Art 37(6)(a)

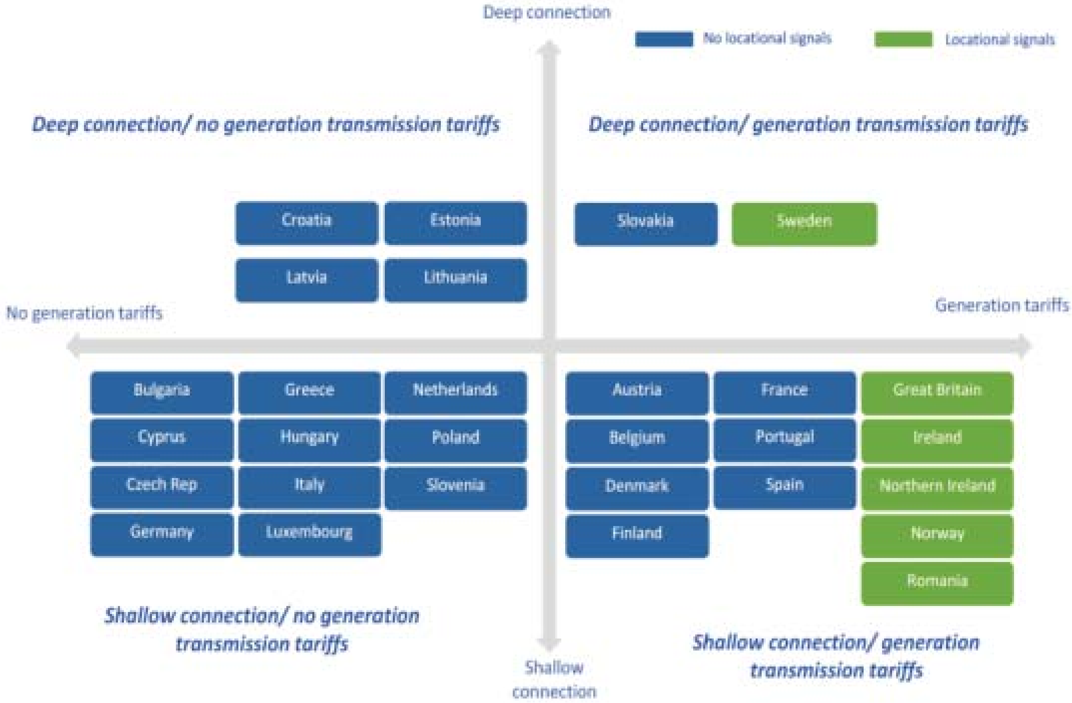
22 Commission Regulation (EU) No 838/210 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, *OJ L 250 24.09.2010, p5-11*

23 0-2 EUR /MWh in Romania; 0-2.5 EUREUR /MWh in UK and Ireland; 0-1.2 EUR/MWh in Denmark, Sweden and Finland; and 0-0.5 EUR/MWh in all other Member States.

24 "*Transmission tariff harmonisation supports competition"*, a report prepared for Energy Norway, May 2013

Subsequently, and with the possibility existing to develop a 'network code[25]' to harmonise transmission tariffs, ACER commissioned a scoping study from Cambridge Economic Policy Associates Ltd (CEPA), which was finalised in August 2015. CEPA concluded that, whilst there are theoretical distortions introduced by different charging regimes in different Member States, the benefits of a short-term regulatory response (e.g. harmonising through a network code) were unlikely to outweigh the potential costs of change. However, they also concluded that in the longer-term, there is a stronger case for further harmonisation "*principally based on the need for greater consistency and application of "optimal" tariff structure that reflect the costs generating by market participants' decisions.*"

Figure 2 – Connection and generation tariffs in various countries



Source: Cambridge Economic Policy Associates Ltd for ACER, based on analysis of ENTSO-E data.

4.3.3. Deficiencies of the current legislation

As detailed above, a framework for transmission tariffs is provided for in the Electricity Directive, Electricity Regulation and in the ITC Regulation[26]. These all provide significant scope for national differences without a view on how any potential negative or distortionary impacts can be resolved. Further, the ACER recommendation has not been implemented into the ITC Regulation.

25 A Commission Regulation developed under procedures laid down in the Electricity Regulation.

26 Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, *OJ L 250, 24.9.2010, p. 5–11*

The Evaluation Report points out that *"whilst the Third Package contains provision on transmission tariffs, their level and design still differ significantly between Member States. This has the potential to distort price signals."*

4.3.4. <u>*Presentation of the options*</u>

Option 0 – BAU

This option would involve maintaining the *status quo*, and the provisions relating to tariffs in the Third Package and associated legislation would remain the same.

Option 0+: stronger enforcement and voluntary cooperation

There is no additional enforcement action to take that would address the points above.

Option 2 would entail a level of voluntary cooperation as part of its implementation – i.e. that regulatory authorities voluntarily work towards implementation of key principles developed by ACER in advance of further legally binding obligations.

Option 1 - Restrict charges on producers (G-charges)

This option would involve eliminating energy-based transmission charges that can be charged on producers (except where they are used for recovering the costs of system losses or costs relating to ancillary services), as set out in the ACER opinion. It would have an effect in the following Member States, who apply such charges[27].

- Denmark
- Finland
- France
- Portugal
- Romania
- Spain

In implementing this option, those Member States would have a choice as to how they then treat generators. They could either remove charges on generators all together, meaning that all tariffs would be charged to consumers, or they could replace them with alternative tariffs, namely ones based on the capacity or a lump-sum tariff. For the purposes of this analysis, it is assumed that these Member States continue to levy charges on generators.

Option 2 - Introduce more extensive and concrete principles on the setting of transmission charges

This option would involve giving responsibility to ACER to develop guidance addressed to national regulatory authorities, which would be developed over a time frame of 1-2 years. It would provide a basis on which NRAs could make their decisions with a view to

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[27] Excluding Austria and Belgium, who apply energy-based charges for ancillary services and/or losses

more concrete legal measures in the future, notably though implementing legislation such as a network code or guideline. Such principles could relate to: the definition and implementation of cost-reflectivity; charges applied to consumers versus charges applied to producers; the types of costs which are to be included; locational and/or time-of-use element of charges; and principles relating to transparency and predictability. It would be accompanied by some higher-level principles in legislation, for example requiring regulatory authorities to minimise any distortions between transmission and distribution tariffs - e.g. on their impact on generators.

Option 3 - Full harmonisation

This option would not only see the process and criteria harmonised but also the components and levels of transmission charges so that the charges on load and production and comparable in each Member States. This would include the elaboration of a harmonised definition of cost-reflectivity, so that all Member States charge producers and/or consumers on the same basis. Further, it would ensure that costs related to ancillary services and losses are treated in the same way.

This option could be accompanied by a requirement that transmission charges include a locational element reflecting, in particular, transmission constraints within a price zone.

4.3.5. <u>Comparison of the options</u>

G-Charges

The option to remove energy-based transmission tariffs on generators has been assessed quantitatively based on ECN's COMPETES model[28]. COMPETES is a power optimisation and economic dispatch model that seeks to minimise the total power system costs of European power market whilst accounting for the technical constraints of the generation units, transmission constraints between the countries as well as transmission capacity expansion and generation capacity expansion for conventional technologies for given generation intermittency (e.g., wind, solar) and RES E penetration in EU Member States. The model also decommissions the existing conventional power plants that cannot cover their fixed costs.

In order to provide a frame of reference, three scenarios were assessed as regards the change on total system costs[29], TSO surplus[30], payments by consumers[31] and producer surplus[32] for a reference year of 2030:

- Reference case where no tariffs are charged. Implicitly, therefore, all the transmission costs are covered by congestion income and electricity prices

[28] " *Transmission Tariffs and Congestion Income Po6licies"*, ECN, DCision, Trinomics (Intermediate Report)

[29] Generation OPEX + Generation CAPEX + Fixed O&M + Transmission Investment

[30] G-charge payments + Congestion income - Transmission CAPEX

[31] Payments consumers make for their electricity use, i.e. electricity use (in MWh) x electricity price (in Euro/MWh)

[32] Short run profits - Gen CAPEX - G-charge payments

charged to consumers - this was created for the purposes of assessing the options below, as opposed to being an option itself.

- Option 0: Reflecting the current situation with different G-tariffs per country (Euro/MWh or Euro/MW differing per country). The tariffs are taken from the ACER internal G-charges monitoring report.
- Option 1: Implementing capacity-based tariffs only in which case energy-based Euro/MWh tariffs of Option 0 are converted to Euro/MW capacity-based tariffs.

A figure for the total social welfare was calculated as {Change in TSO surplus + Change in Producer surplus - Change in Consumer payments}. The results for the total and comparison of the options are provided in table 1 and 2 respectively.

Table 1 – total values, all countries (million EUR)

	System Costs	TSO surplus	Consumer payments	Producer surplus
Reference (no tariffs)	85,082.2	2,102.3	226,821.0	138,455.7
Option 0 (current situation)	85,094.7	3,044.6	227,617.6	138,282.9
Option 1 (cap.-based tariffs)	85,094.0	2,875.1	227,298.2	138,141.1

Table 2 – option comparison, all countries (million EUR)

	System Costs	TSO surplus	Consumer payments	Producer surplus	Social welfare
Option 0 vs Reference	12.5	942.3	796.6	-172.8	-27.1
Option 1 vs Reference	11.8	772.8	477.2	-314.6	-19.0
Option 1 vs Option 0	-0.8	-169.5	-319.4	-141.8	8.1

Moving from the current system (Option 0) would result in an increase in economic efficiency of generation dispatch and investment decisions as well as overall competition between generators. More specifically, there would be some limited effect on dispatch and investment decisions of generators in countries that have to replace energy-based by capacity-based or lump sum G-charges. On the other hand, decisions of generators in countries that currently either have no energy-based G-charges or only non-energy based G-charges in place would not be affected. Cross-border competition between generators is likely to induce regulatory competition between Member States and, as such, likely to serve as an implicit upper limit to all types of G-charges, preventing larger divergence of within the EU. However, this this does not imply that G-charges will be set to their optimal long-run cost-reflective level i.e. the level that stimulates generators and consumers to take investment and siting decisions that minimise overall system costs, which is the sum of generation, network, and societal costs. Rather it is likely that the G-charges of the largest Member States in Continental Europe become the benchmark. In the absence of incentives for multilateral coordination of country practices regarding transmission charges for generators (either regional or EU-wide), this option can therefore be considered as incomplete. As can be seen from the above, the social benefits of moving from the current system would be in the region of EUR 8 million a year – a small proportion of overall system costs. This risks being outweighed by implementation costs.

Principles for transmission charges

It is naturally more difficult to quantitatively assess the impacts of this option, as they will by-and-large depend on the precise design of such principles and the extent to which they are implemented prior to any legal mandate (e.g. from implementing legislation such as a network code). Therefore this option is assessed qualitatively.

A harmonisation of the tariff principles to better reflect the grid costs will have a positive impact on the efficiency of dispatch and investment decisions by generators. Concerning the latter, harmonised tariff principles will improve the investment climate for power generation by offering a higher predictability with regard to the expected tariff development. It will overall reduce competition distortions amongst generators, but the impact of tariff harmonisation on the competitiveness of individual generators can be positive or negative depending on the current situation.

As discussed above, there are a number of issues that need to be addressed in the design of tariff structures. These include the extent to which charges are applied to generators as compared to consumers (the Generation: Load or "G:L" split), the basis on which they are charged, the interpretation of the principle of 'cost reflectivity,' whether there are signals on location or time of use, etc. Whilst the discussion here has mostly been focused on generators and the wholesale market, a significant proportion of transmission tariffs on are charged on consumers/load – all Member States apply charges to load, with some applying all of them (15). Therefore the design of tariff structures can have a significant impact on consumers, both financially and economically, and on their behaviour. There are clearly a number of complexities which will need discussion among regulators, TSOs and stakeholders to determine the most beneficial approach.

Despite the fact that national tariff differences are only one of the drivers of current distortions of dispatch and investment decisions between Member States, the focus on cost reflectivity of transmission signals is key in an increasingly interconnected system in order to prevent negative spill-over effects.

Harmonisation

Full harmonisation would involve decisions on many of the same topics as mentioned above, but determining them in legislation immediately. It would require upfront decisions on the 'optimal' tariff structure, something that so far has not been determined with a clear articulation of the benefits. As mentioned above, there already exists a legal mechanism for harmonising tariffs – Article 8 of the Electricity Regulation already provides the ability to create implementing legislation, in the form of a network code, something that would be developed collaboratively by TSOs, regulators, ACER and stakeholders. Doing this as part of Market Design is very unlikely to elicit better results than could be achieved with the detailed and ongoing participation of experts that the development of a network code would involve. Further, flexibility would be compromised. Given the complexity and the amount of 'unknowns' there is a significant risk that any attempt to fully harmonise would result in issues that could only be identified once Member States start to implement the requirements; a network code allows for significantly more flexibility to respond to such issues if and when they arise.

Requirements set out in an ordinary legislative act would prove much more difficult to adapt.

There are two sub-issues that have also been considered as part of this option: that of harmonised charges relating to ancillary services and grid losses; and locational-charging.

There is significant diversity in charging methodologies with regards to ancillary services. For instance, in most Member States, all costs for balancing services are recovered via charges on load. Only in a few Member States do generators pay grid charges that comprise a specific contribution for the cost related to balancing services[33]. With regards to grid losses, again most European countries recover them through charges on load, but in a few countries the related cost is partly or fully charged to generators[34].

If charges for ancillary services were to be harmonised, the impact on short-term and long-term electricity system efficiency would depend on the level of the charges and the charging modalities but may not be substantial. If charges for ancillary services were to be more correctly and transparently allocated to the market parties (generation and load) on basis of needs of the parties, market operators would contribute to minimising the overall need for such services, particularly frequency-related services, with more flexible demand and supply. It could, however, contribute to a higher cost-reflectiveness and fairer cross-border competition amongst generators as the currently diverging charging practices and cost allocation can lead to competition distortions between power generators active in the same integrated regional market.

The impact of a harmonised charging method of grid losses via a specific tariff on the short-term and long-term electricity system efficiency would be very limited. Only if grid losses are calculated and charged individually to grid users would there be a higher impact on the short and long-term system efficiency. There is, however, scope to correct competitive distortions on generators, although this will only have an impact in those few Member States where losses are (partly) charged to generators; in the large majority of Member States grid losses are entirely charged to load.

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[33] Austria (2.81 EUR/MWh in 2015), Belgium (0.9111 EUR/MWh, which represents 50 % of the overall reservation cost for balancing services), Bulgaria (3.65 EUR/MWh to be paid only by wind and solar generators to cover the cost for balancing services), Finland (0.17 EUR/MWh), Ireland (0.3 EUR/MWh), Northern-Ireland (0.31 EUR/MWh), Norway (0.21 EUR/MWh – the costs for procuring balancing services are in Norway divided equally between generation and load) and Sweden (0.087 EUR/MWh). In Great Britain, the costs incurred by the TSO (NGET) in balancing the transmission system are recovered through Balancing Services Use of System (BSUoS) Charges, which are shared equally between generators and suppliers. *ACER, Internal Monitoring Report on Transmission charges paid by the electricity producers*, May 2016.

[34] Austria (0.45 EUR/MWh in 2015), Belgium (balancing responsible parties are obliged to inject, depending on the time, 1.25 or 1.35 % more than their offtake from the grid), Greece (average = 1.08 EUR/MWh based on zonal Generation Losses Factors), Ireland and Northern-Ireland (1.36 EUR/MWh), Norway (average = 0.57 EUR/MWh based on marginal loss rates which are different depending on the location and the time), Romania (0.23 EUR/MWh) and Sweden (0.40 EUR/MWh) - ACER, *Internal Monitoring Report on Transmission charges paid by the electricity producers*, (May 2016).

With regard to providing appropriate locational signals for investment and dispatch of generation through tariffs, clearly this can only be achieved where generators are charged tariffs (so in 12 Member States) and, with regards to the latter, only where there is energy-based charging (8 Member States). Administratively setting tariffs to affect dispatch could add significant distortions into the energy market and requiring this is not an option that is explored further. As to investment signals, i.e. making it more expensive to locate in areas of less need, and less expensive in areas of higher need, proponents would argue that it gives economic signals about where to site new generation capacity and use existing capacity, and that it reflects the costs to the transmission network that generators cause. However, opponents believe that locational charging is designed to reflect a generating mix predicated on generation close to centres of demand and not designed to encourage a fundamental shift to more mixed and geographically spread energy supply. Any concrete impact of location-based charging on economic efficiency will largely depend on the level of the fee and its form, and it is not clear that this would override other factors influencing siting (regulatory, planning, meteorological, etc.). Further, it is potentially complex to implement and could add uncertainty to generators. If price zones are formed based on structural congestion, part of an objective of Market Design (see Annex 4.2) this could anyway remove the need to introduce locational signals by other means – i.e. as the energy price would provide such signals. This is not to say that the approach is not succeeding in those countries that already employ it (e.g. GB, Sweden) or that it is definitely unsuitable for the future, but rather that the first step should be to implement appropriate defined price zones and that further, detailed consideration is needed at the regulatory level on whether and how to implement such an approach. It is, therefore, not considered an appropriate response to design or mandate its introduction as part of this legislative package.

Summary

Given the number of design features and complexities regarding transmission tariffs, and the potentially small benefits associated with harmonising the less-complex aspects individually, it is concluded that the most appropriate option is to leave any full harmonisation to future implementing legislation as part of a network code or, if appropriate, through an amendment to existing implementing legislation[35]. This will minimise disruption and implementation costs, allow the precise package to be worked up over time and with full involvement of experts, and also allow for the interactions between distribution tariffs and transmission tariffs, and their impacts on consumers and generators at both connection-levels, to be more fully reflected. Further, it will allow time to determine the most beneficial approach and tackle the most significant issues holistically. The development of principles to guide NRAs when designing tariffs regimes (Option 2) would provide the first step in this process, and facilitate early decisions and implementation prior to any legally binding instrument. As the topic falls within the regulators' field of competence, this would be appropriately led by ACER. Further, augmentation of the high-level principles in the Electricity Regulation is necessary to reflect evolution of the market since they were originally introduced, for

[35] E.g. changes to G-charges could be effected by amending the ITC regulation.

example to avoid any discrimination between distribution-connected and transmission-connected generation when setting or approving tariffs.

4.3.6. *Subsidiarity*

Charges applied to generators in relation to their connection to, and use of, networks can be significant. Differences in these charges can therefore have an effect on decision-making, whether it is on investment locations or on dispatch of energy, and can therefore add distortions into the market. Given the highly integrated nature of EU electricity markets, this can add distortions between Member States.

EU-level action is therefore warranted, in order to ensure the minimum degree of harmonisation needed to avoid distortion in investment and generation is achieved. The Third Package already lays down a number of rules relating to these changes (notably Article 14 of the Electricity Regulation), and also requires NRAs to take an active role (under the Electricity Directive). Further provisions relating to transmission tariffs are contained in the inter-transmission system operator completion mechanism (ITC) Regulation, aimed at the issues mentioned above.

Whilst much has been achieved, there is still scope for improvement, particularly given the importance of minimising distortions to the benefit of consumers. EU-action is needed to addresses this as it needs to be coordinated across the EU.

4.3.7. *Stakeholders' opinions*

Stakeholder feedback suggests there is a case for change, particularly in the medium to long-term. In 2015, ACER ran an exercise looking at potential harmonisation of tariffs through the development of a network codes. This included stakeholder questionnaires (run by Cambridge Economic Policy Associated – CEPA). In their report, CEPA highlighted a number of points:

- The majority of stakeholders (79 responses) across European countries consider that the current electricity transmission tariff structures do impact on the efficient functioning of the European electricity market;
- Around 80% of respondents agreed that generators' operational and investment decisions are affected by transmission tariff structures;
- The majority of respondents also considered differences in current transmission tariff structures across Europe to be a source, or a potential source, of regulatory and market *failure* in the IEM. Differences in transmission tariff structures across European countries were identified by stakeholders as a problem today and potentially in the future, citing distortions to operational (as well as investment decisions) as a source of regulatory or market failure;
- Over 60% of respondents also agreed or strongly agreed that differences in transmission tariff structures across European countries could hamper cross-border electricity trade and/or electricity market integration. Energy-based tariffs were cited as a particular issue;
- Around 70% of respondents believed that there are benefits that can be achieved through harmonisation of transmission tariff structures. Only 7% of all respondents rejected the idea that harmonisation of transmission tariffs would be beneficial for the IEM;

Further, Eurelectric, in their market design publication[36], state that "[r]*egarding transmission tariffs applied to generators, their structure and methodologies to compute the costs need to be harmonised. Furthermore, their levels should be set as low as possible, in particular the power based charges (€/MW) which act as a fixed cost for generation and therefore distort investment decisions*."

[36] *"Electricity market design: Fit for the low carbon transition,"* Eurelectric (2016)

4.4. Congestion income spending to increase cross-border capacity

4.4.1. *Summary table*

Objective: The objective of any change should be to increase the amount of money spent on investments that maintain or increase available interconnection capacity				
	Option 0: Business as usual	**Option 1**	**Option 2**	**Option 3**
Description	This option would see the current situation maintained, i.e. that congestion income can be used for (a) guaranteeing the actual availability of allocated capacity or (b) maintaining or increasing interconnection capacities through network investments; and, where they cannot be efficiently used for these purposes, taken into account in the calculation of tariffs. Stronger enforcement: current rules do not allow for stronger enforcement. Voluntary cooperation: would offer no certainty that the allocation of income would change.	Further prescription on the use of congestion income, subjecting its use on anything other than (a) guaranteeing the actual availability of allocated capacity or (b) maintaining or increasing interconnection capacities (i.e. allowing it to be offset against tariffs) to harmonised rules.	Require that any income not used for (a) guaranteeing availability or (b) maintaining or increasing interconnection capacities flows into the Energy part of CEF-E or its successor, to be spent on relieving the biggest bottlenecks in the European electricity system, as evidenced by mature PCIs.	Transfer the responsibility of using the revenues resulting from congestion and not spent on either (a) guaranteeing availability or (b) maintaining capacities to the European Commission. De facto all revenues are allocated to CEF-E or successor funds to manage investments which increase interconnection capacity.
Pros	Minimal disruption to the market; consumers can benefit from tariff reductions – unclear whether benefits of better channelling income towards interconnection would provide more benefits to consumers, given that it may offset (at least in part) money spent on interconnection from other sources.	More guarantee that income will be spent on projects that increase or maintain interconnection capacity and relieve the most significant bottlenecks; could provide around 35% extra spend; approach reflects the EU-wider benefits of electricity exchange through interconnectors; can be linked to the PCI process.	Guarantees that income will be spent on projects that increase or maintain interconnection capacity and relieve the most important bottlenecks; could provide up to 35% extra spend; approach reflects the EU-wider benefits of electricity exchange through interconnectors; firm link with the PCI process.	Best guarantee that income will be spent on the biggest bottlenecks in the European electricity system, ensuring the best deal for European consumers in the longer run; approach reflects the EU-wider benefits of electricity exchange through interconnectors; to be linked to the PCI process.

Cons	Missing a potentially significant source of income which could be spent on interconnection and removing the biggest bottlenecks in the EU.	Restricts regulators in their tariff approval process and of TSOs on congestion income spending. Additional reporting arrangements will be necessary. Requires stronger role of ACER.	Restricts regulators in their tariff approval process and of TSOs on congestion income spending. Could mean that congestion income accumulated from one border is spent on a different border or different Member States. Additional reporting arrangements will be necessary. Requires stronger role of ACER.	Could prove complicated to set up such an arrangement; could mean that congestion income accumulated from one border is spent on a different border or different Member States. Requires a decision to apportion generated income to where needs are highest in European system. Will face national resistance. Will require additional reporting arrangements to be put in place. Requires stronger role of ACER.
Most suitable option(s): Option 2 – provides additional funding towards project which benefit the EU internal market as a whole, while still allowing for national decision making in the first instance. Considered the most proportionate response.				

4.4.2. *Description of the baseline*

Congestion[37] income arises across an interconnection due to price differences on each side of it. Such effects happen between price areas (i.e. bidding zones), as opposed to between Member States. The higher the price difference, the greater the income generated. Conversely, the greater the levels of interconnection, the more arbitrage opportunities and, therefore, the lower the price differences each side. Congestion income per MW is therefore lower.

The issue of optimising interconnection capacity from a private versus social cost-benefit perspective has been analysed, among others, by De Jong and Hakvoort (2006; see also De Jong, 2009).[38] They show that, under certain assumptions (two-node network with perfect competition and linear supply and demand curves), the capacity that maximises social benefits is twice the capacity that maximises private benefits. This relationship changes a bit, however, when investment costs are also taken into account. In that case, De Jong and Hakvoort show that the interconnection capacity that maximises social value exceeds the capacity that maximises private profits by even more than a factor of two.

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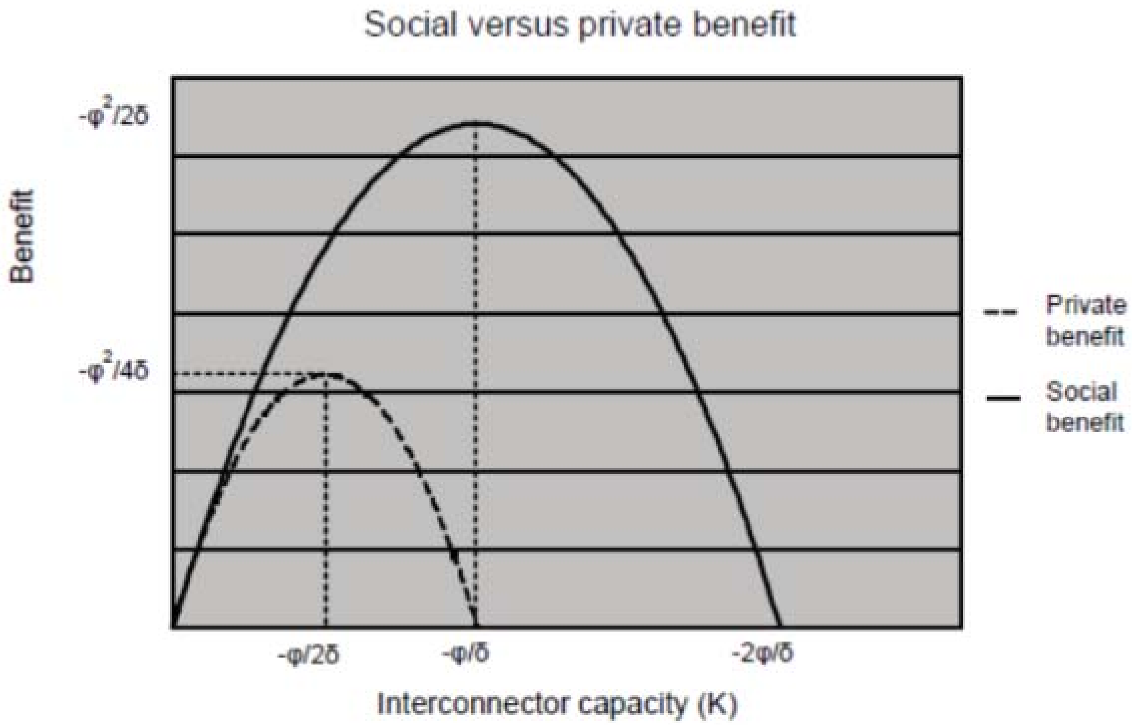
[37] The term 'congestion' means a situation in which an interconnection linking national transmission networks cannot accommodate all physical flows resulting from international trade requested by market participants, because of a lack of capacity of the interconnectors and/or the national transmission systems concerned.

[38] De Jong, H., and R. Hakvoort (2006), *Interconnection Investment in Europe – Optimizing capacity from a private or a public perspective ?*, in : Proceedings of Energex 2006, the 11th international energy conference and exhibition, 12-15 June 2006, Stavanger, Norway, pp. 1-8. De Jong, H. (2009), *Towards a single European electricity market – A structural approach to regulatory mode decision-making*, Ph.D.-thesis, Technical University Delft, the Netherlands.

Figure 1 - Optimum interconnection capacity from a social versus private benefit perspective



Source: De Jong (2009), p. 261 (see also De Jong & Hakvoort, 2006))

Congestion income from interconnection capacity is a major source of revenues for TSOs' investment in network expansion. Therefore, in theory, TSOs will invest in new interconnection capacity as long as the congestion income outweighs the investment and operational costs (including a reasonable rate of return) and the potential decrease of congestion income on existing cross zonal interconnectors in the case that the new interconnector serves as a substitute to existing interconnectors. From a social point of view, this may result in underinvestment in interconnection capacity and, hence, in a sub-optimal level of cross-border transmission capacity.

Partly to address this, Article 16 of the Electricity Regulation seeks to restrict how congestion income can be used[39]. Specifically, it only allows it to be used to:

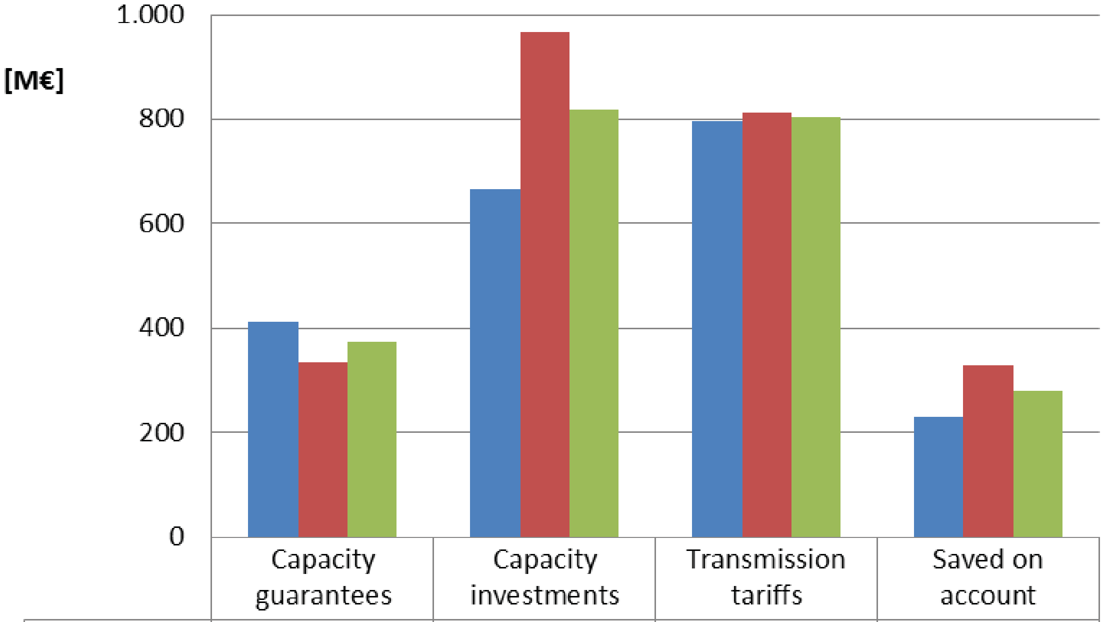
1. guarantee the availability of allocated interconnection capacity;
2. maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors;
3. to be offset against network tariffs; or
4. held on account until it can be spent on one of the above.

[39] In the case of new interconnectors, exemptions can be given to these requirements subject to a number of conditions being fulfilled.

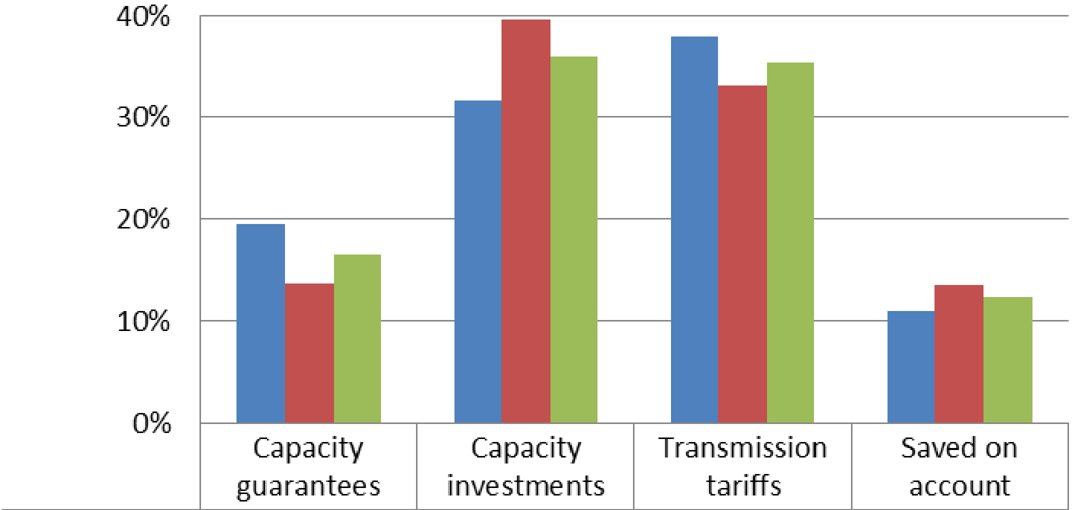
According to data from ENTSO-E, the total amount of TSO net revenues from congestion management on interconnections was EUR 2.3 billion in 2014 and EUR 2.6 billion in 2015. Figure 2 presents the spending of congestion revenues in 2014-15 aggregated for all members of ENTSO-E, both in million EUR and as a % of total annual revenues. These revenues amounted to, on average, EUR 2.275 million per annum in 2014-2015. Figure 2 shows that out of this amount, on average, EUR 374 million was spent on capacity guarantees (16%), EUR 817 million on capacity investments (36%), EUR 804 million on reducing transmission tariffs (35%) and EUR 280 million saved on an account (12%). This implies that, on average, about half of the congestion revenues in 2014-15 were used to guarantee, maintain or increase interconnection capacity and, hence, that – in principle – there is room for increasing this share by alternative Options.

It should be noted, however, that changing the rules on spending of congestion income may not by itself be sufficient to stimulate investment in relieving the biggest bottlenecks in the EU. There are a number of reasons why investment in interconnection capacity might not be forthcoming: they are complex projects with a number of socio-economic impacts, and often face barriers relating to, for example, planning; the decisions are complex, and often require the involvement of two or more parties; additional investments may be needed in national networks in order to accommodate new capacity. Further, TSOs are able to cover the investment and operational costs of interconnectors – which are approved by their NRAs – not only from congestion revenues but also, or even exclusively, from regulated transmission tariffs. Therefore, there is theoretically already a source of funding for such projects, although in practice the regulated tariff system may be considered too restrictive for socially optimal investments in interconnection capacity, for instance because certain costs may not be approved to be part of the regulated cost base, or because the allowed rate of return may be considered too low to cover the risks, uncertainties or other challenges involved.

Figure 2- Spending of congestion revenues in 2014-15 (in million EUR and as % of total annual revenues for all countries)



	Capacity guarantees	Capacity investments	Transmission tariffs	Saved on account
2014	412	666	797	230
2015	336	968	812	330
Av. 2014-15	374	817	804	280



	Capacity guarantees	Capacity investments	Transmission tariffs	Saved on account
2014	20%	32%	38%	11%
2015	14%	40%	33%	13%
Av. 2014-15	16%	36%	35%	12%

Source: ENTSO-E (2014-15)

4.4.3. <u>*Deficiencies of the current legislation*</u>

Current legislation is not providing for sufficient investments in bottlenecks within the European electricity system. Whilst, as highlighted above, this is unlikely to be due, at least solely, to how congestion income is spent, there is clearly scope for significantly

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more funding to be directed toward this ends from congestion income. As demonstrated from the above figures, the amount spent on increasing or maintaining interconnection capacity is less than half of the available funds. Further, despite existing bottlenecks and interconnection levels well below the optimum ones, the legislation offers incentives to NRAs to retain congestions, as the income they generate can be used to lower national tariffs. There are also significant deficiencies in transparency with regards to the spending of congestion income. Whilst current legislation contains obligations relating to transparency, this is ineffective in practice and it proves difficult to assess how the provisions of Article 16 are being applied. For example, it is unclear:

- how the TSOs decide on the use of congestion revenues for either guaranteeing, maintaining or increasing interconnection capacity;
- whether and how the NRAs check (i) that TSOs have used congestion revenues efficiently for either guaranteeing, maintaining or increasing interconnection capacity, and (ii) that the rest of the revenues cannot be efficiently used for these purposes;
- on which criteria the NRA decides on the maximum amount used as income to be taken into account when approving or fixing network tariffs;
- how the congestion revenues are used during the period they are put on a separate account;
- the projects towards which the funds are being allocated, including the split between investments towards capacity maintenance and capacity increases.

The Evaluation Report points out that "*another problem is the lack of adequate and efficient investment in electricity infrastructure to support the development of cross-border trade. ACER's recent monitoring report and other reports on the EU regulatory framework stress that the incentives to build new interconnections are still not optimal. In the current regulatory framework, TSOs earn money from so-called congestion rents. If TSOs reduce congestion between two countries, their revenues will therefore decrease. The Third Package has identified this dilemma and addressed through obliging TSOs to use congestion rents either for investments in new interconnection or to lower network tariffs. Experience with this rule has, however, shown that most TSOs prefer to use congestion rents to lower their tariff to investing into new interconnectors.*"

4.4.4. Presentation of new measures/options

Option 0 – Do nothing.

This would maintain the *status quo*, i.e. rules on spending covered by Article 16 of the Electricity Regulation. The methodology currently being developed under the Capacity Allocation and Congestion Management regulation (CACM) would provide the main rules on how the income is allocated between TSOs on each border.

Option 0+: Non-regulatory approach

Stronger enforcement of existing rules will not allow an improvement of the current situation.

Voluntary cooperation will provide no certainty that there will be a change in the current allocation of congestion income. Given there are already rules in place, a change to these rules is needed to address the issue.

Option 1 – Harmonised use of congestion income

The first option would maintain all the options for the use of congestion income as already provided for in the regulation, but be more prescriptive about when it can be taken into account in the calculation/reduction of network tariffs. More specifically, it would require that its use on anything other than (a) guaranteeing the actual availability of allocated capacity or (b) maintaining or increasing interconnection capacities be subject to harmonised rules developed by ACER.

These rules would clearly define the situation when, and when not, the alternative options could be pursued. Indicatively, the possibility to decrease the network tariff through congestion income would be allowed only when there is clear and justified evidence, according to the ACER rules, that there are no cost-effective projects that would be more beneficial for social welfare than tariff reduction. Rules would also detail how long/which revenues could be kept in internal accounts until they can be effectively spent for the above purposes.

This option would be combined with more transparency and additional rules for publication and monitoring of this spending.

Option 2 – Harmonised use of congestion income with basic CEF option

The second option would, similarly, restrict spending to (a) guaranteeing availability or (b) maintaining or increasing interconnection capacities. If the income cannot be effectively used on (a) or (b), it would flow into the Connecting Europe Facility for Energy (CEF-E) or its successor, and be spent on relieving the biggest bottlenecks in the European electricity system, as evidenced by mature PCIs. Unlike Option 1, there would be no option to use the income when calculating tariffs until such time that all the biggest bottlenecks have been removed (which practically will not happen in the foreseeable future).

This option would, similarly to Option 1, include harmonised compliance rules to be set out and monitored by ACER, and combined with more transparency.

Under this option, it is possible that congestion revenues that would normally be used to lower the national network tariff accrued in one Member State will be spent in another Member State allowing spending on those projects that would bring the greatest benefits to the EU as a whole.

Option 3 – Harmonised use of congestion income with full CEF option

The third option is an extension of the second. TSOs would, at the national level, be permitted to use income for (a) guaranteeing the actual availability of allocated capacity or (b) maintaining interconnection capacities. However, they would not be permitted to use it to *increase* interconnection capacity, and neither could it be used against tariffs.

Instead, all income not spent on (a) and (b) above would be directed to the European Commission, *de facto* to the CEF-E or successor funds, to manage interconnection capacity. This way, the revenues that, up to now can be used by TSOs/NRAs for increasing capacity or lowering network tariffs, would be spent on the biggest bottlenecks in the European electricity system as evidenced by mature PCIs. Again, as with Option 2, if and when all these are removed, income could then be taken into account when calculating tariffs.

This option would, similarly to Option 1, include harmonised compliance rules to be set out and monitored by ACER, and combined with more transparency.

Again, under this option it is possible that congestion revenues accrued in one Member State will be spent in another Member State allowing spending on those projects that would bring the greatest benefits to the EU as a whole.

4.4.5. *Comparison of the options*

The options have been compared against the following criteria:

- Effectivity. Effectivity implies that, as much as possible, congestion income is used to maximise the amount of cross-border capacity available to market participants. The criterion assesses whether and to what extent the Options achieve this objective;
- Efficiency. Efficient use of congestion income means that the procedure for the spending of congestion income provides a simple and straightforward approach to guaranteeing that congestion income is used for maintaining or increasing the interconnection capacity;
- Transparency. The spending of congestion income should be transparent and auditable;
- Robustness. The spending rules should be set in such a way to avoid influence over the rules beyond what it envisaged;
- Predictability. The spending rules should allow a forecast of the financial outcome and allow for reasonable financial planning by the TSOs involved;
- Proportionality. Congestion income policy options should be commensurate with the problem i.e. not going beyond what is necessary to achieve the objectives, limited to those aspects that Member States cannot achieve satisfactorily on their own, and minimise costs for all actors involved in relation to the objective to be achieved;
- Smoothness of transition. The current congestion income spending should not be changed in a radical way in the short-term in order to limit the financial impact on all system participants.

Effectivity

With respect to the effectivity of the policy options, all three positively contribute in more or less the same manner. Currently, congestion income may be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs and/or fixing network tariffs. In all three options this type of usage will be strongly restricted or forbidden causing a larger share of the congestion income to be allocated to maintaining and/or increasing cross-border capacity. However, for the actual construction of these links, there may be additional barriers like the licensing procedures for the new corridors, so the availability of more financial resources may not in all cases guarantee interconnection expansion.

Efficiency

Currently, TSOs and NRAs have the possibility to allocate the congestion revenues in the most economically efficient manner. However, due to flexibility at the national-level it cannot be guaranteed that congestion income will always be spent on maintaining and/or increasing the available interconnection capacity. In each of the three options the level of freedom for TSOs and NRAs to decide otherwise will be significantly reduced.

Since in Option 2 congestion income for investments are managed at a European level, whereas the operational measures to guarantee or maintain the interconnection capacity are dealt with nationally, this Option might be less effective than the other two. Furthermore, there is some possibility that Member States prefer to withhold funds from being transferred to a European institution by previous spending on operational measures.

Transparency

There are currently reporting obligations for the TSO on the spending of congestion income. It is nonetheless not entirely clear, which criteria are applied for allocating congestion income to operational measures, investments in capacity expansion or inclusion in the transmission tariffs. It is expected that each of the three options will increase the transparency of the allocation and spending of congestion income.

Robustness

The present methodology for spending congestion income is monitored by the NRAs whereas the revenues themselves are ring fenced. There is not much room to spend the income for other purposes than that envisaged. Each of the three Options further narrows down the discretion of TSOs and NRAs. In each Option a larger share of congestion income will be used for investments, since decision making is either more heavily regulated or transferred to the European level.

Predictability

Currently, it is not clear how congestion income will be spent. It does not only depend on the operational costs needed to guarantee the cross-border capacity, but also to the discretion of the TSOs (and the approval of the NRAs) in deciding how to spend the income. Each of the three Options contributes to a better predictability. However, the first option leaves more freedom to Member States to decide on new investments than the other two options, under which the income is added to the CEF-E funds, which are only used for PCI investment projects. In the latter case the predictability of the manner of spending is very good.

With respect to spending congestion income on operational matters, clearer rules will contribute to higher transparency on the amount of funds needed for it. This will materialise in all three options.

Proportionality

If the objective of the policy options is to enhance the actual availability of the interconnection capacity by relieving the financial constraint, each option that effectively increases the financing of investments can be considered as proportional. With respect to the implementation differences between the three options, it is debatable which measure is more (or less) proportional than the other: adding detailing regulation (as in Option 1) or shifting decision making power from the national to the European level (as in Options 2 and 3).

Smoothness of transition

The smoothness of transition is assessed with respect to the amount of change involved when implementing each Option with reference to the current situation. The implementation of additional regulation does not significantly change the present powers of TSOs and NRAs, which is why Option 1 is positive with respect to smoothness of transition.

For Options 2 and 3 decision making on new investments and operational measures for maintaining the interconnection capacity shifts to the European level, which will have a larger impact. It is possible that there will be objections to such a change, especially the third option where more congestion income is managed on this level.

Summary

Overall, do nothing is not considered an appropriate response, as it does not address the deficiencies in the current legislation. Changing the current arrangements will not only increase the incentives on TSOs, but also on Member States and NRAs – i.e. there is a sum of money that must be spent on interconnection in some form. Whilst tariffs can always be used to fund such developments, there are counter-incentives, i.e. to keep tariffs lower by limiting development to that which is strictly necessary as opposed to being of longer-term benefit and of benefit to the EU internal market as a whole.

Option 1 is the least change, and the most flexible. However, due to this flexibility it is also the option which could see the least amount of money redirected from being used when calculating tariffs or from internal accounts towards projects that increase interconnection capacity. Option 3 would be a significant change and takes away all national-level decision-making on new investment using congestion income. This may be less proportionate than allowing some national autonomy, at least in the first instance if it achieves broadly the same ends. Option 2 would see the same financial potential for new network investments that increase interconnection capacity – i.e. up to EUR 1.14 billion per annum. It is therefore considered the most proportionate response to achieve the ends sought.

4.4.6. <u>Subsidiarity</u>

The use of congestion income by TSOs has already been addressed at EU-level as part of the Third Package. The issue is very much one of a cross-border nature, as the majority of congestion income is raised on infrastructure that crosses Member State borders. A common approach across the EU is necessary to ensure a level-playing field between Member States and leaving the issue at national, or bi-lateral, level risks inconsistent application.

35% of congestion income was used on average over 2014 and 2015 to reduce tariffs, despite the increase of cross-border trade in electricity between most EU Member States and the growing need to strengthen the physical connection of electricity markets. Also, maintaining grid stability becomes more challenging as increasing shares of variable renewables enter the energy mix; higher interconnection levels could decrease the necessity for redispatch and lead to lower network tariffs. These issues, given their cross-border impacts, can only be dealt with at an EU-level.

Given that the most common use of congestion income does not seem to address the current needs of grid development and maintenance, further EU action is necessary to ensure that there is an increase of the proportion of congestion income spent on maintaining or increasing interconnection.

4.4.7. *Stakeholders' opinions*

Whilst there was not a specific question in the energy market design consultation on congestion income, and many respondents did not comment on the issue, some did express views. For example, comments included:

> *"... It should be a common European interest to reduce or remove permanent bottlenecks between countries within the EU. Primarily it should be done by using the congestion incomes for investments instead of simply managing the congested transmission lines. There is no need for separate capacity pricing for the energy only markets."*

> *"At the moment, income from congestion management shall be used to mitigate the bottleneck or decrease the end user tariffs. However clear mechanism for setting up the financing of the new projects shall be in place (including needed change in accounting standards and income tax rules). With the new investment the respective bottleneck is dismissed and there is no further income from congestion management. This makes the return on investment impossible."*

> *"According to the Communication it is essential to achieve the previously established target value of 10% for the interconnection of electricity networks, and its increase to 15%. To this end, the current effective EU regulation provides adequate support. At the same time, according to the Commission's concept the utilisation of fees currently charged for congestion management should be regulated in a manner which would facilitate the development of the electricity system. We would be in a position to support this concept if there is guarantee that once the target value has been achieved by a Member State the revenues could still be used for other purposes as well (e.g. tariff cuts)."*

> *"...funds* [for cross-border redispatching] *could come from congestion rents which are not possible to be attached to a border anymore in a flow-based world. This common TSO income should be spent commonly on costly coordinated actions."*

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Congestion income spending to increase cross-border capacity

5. Detailed measures assessed under Problem Area II, Option 2(2) (improved energy markets - CMs only when needed, based on common EU-wide adequacy assessment (and Option 2(3) (Improved energy market, CMs only when needed based on common EU-wide adequacy assessment, plus cross-border participation)

262 **Congestion income spending to increase cross-border capacity**

5.1. Improved resource adequacy methodology

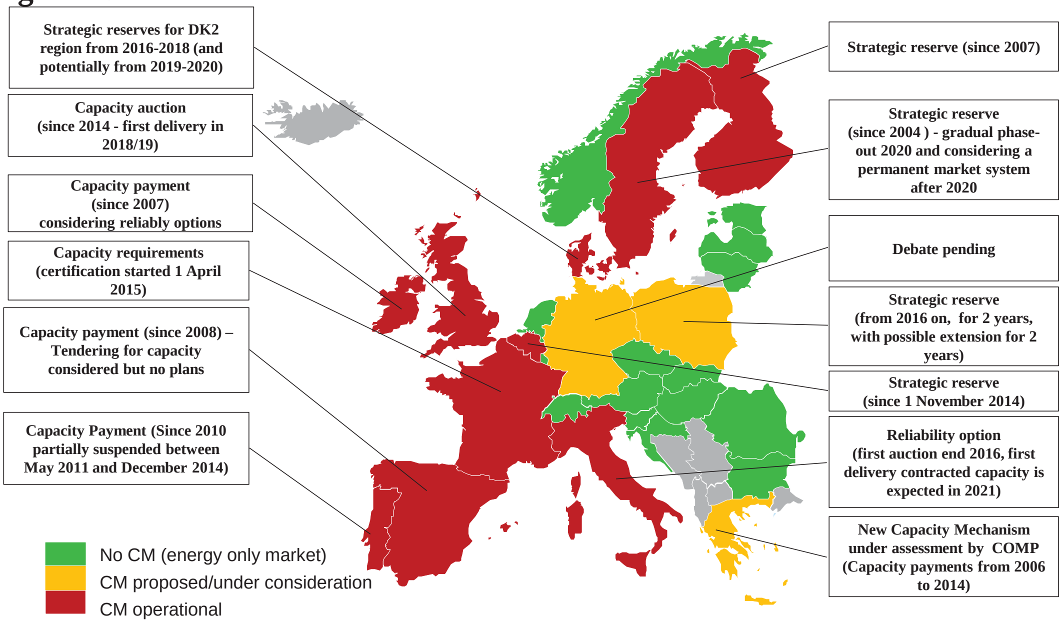
5.1.1. *Summary table*

Objective: Pan-European resource adequacy assessments				
	Option 0	**Option 1**	**Option 2**	**Option 3**
Description	Do nothing. National decision makers would continue to rely on purely national resource adequacy assessments which might inadequately take account of cross-border interdependencies. Due to different national methodologies, national assessments are difficult to compare.	Binding EU rules requiring TSOs to harmonise their methodologies for calculating resource adequacy + requiring Member States to exclusively rely on them when arguing for CMs.	Binding EU rules requiring ENTSO-E to provide for a single methodology for calculating resource adequacy + requiring Member States to exclusively rely on them when arguing for CMs.	Binding EU rules requiring ENTSO-E to carry out a single resource adequacy assessment for the EU + requiring Member States to exclusively rely on it when arguing for CMs.
Pros	Stronger enforcement: Commission would continue to face difficulties to validate the assumptions underlying national methodologies including ensuing claims for Capacity Mechanisms (CMs).	National resource adequacy assessments would become more comparable.	In addition to benefits in Option 1, it would make it easier to embark on the single methodology.	In addition to benefits in Options 1 & 2, it would make sure that the national puzzles neatly add up to a European picture allowing for national/ regional/ European assessments. Results are more consistent and comparable as one entity (ENTSO-E) is running the same model for each country.
Cons		Even in the presence of harmonised methodologies national assessment would not be able to provide a regional or EU picture.	Even in the presence of a single methodology, national assessments would not be able to provide a regional or EU picture. National TSOs might be overcautious and not take appropriately cross-border interdependencies into account. Difficult to coordinate the work as the EU has 30+ TSOs.	It would potentially reduce the 'buy-in' from national TSOs who might still be needed for validating the results of ENTSO-E's work.
Most suitable option(s): Option 3 - this approach assesses best the capacity needs for resource adequacy and hence allows the Commission to effectively judge whether the proposed introduction of resource adequacy measures in single Member States is justified.				

5.1.2. *Description of the baseline*

Based on perceived or real resource adequacy concerns[40], several Member States have recently introduced resource adequacy measures. These measures often take the form of either dedicated generation assets kept in reserve or a system of market wide payments to generators for availability when needed (Capacity mechanisms or 'CM's).

Figure 1: CMs in the EU



Source: ACER 2015 Monitoring report

National resource adequacy assessments

To determine whether these concerns require the introduction of a CM, Member States[41] first need to carry out an assessment of the adequacy situation. Indeed, all Member States that are part of DG COMP's Sector Inquiry on Capacity Mechanisms measure the security of supply situation in their country by carrying out an adequacy assessment in which one or more methodologies are applied that give an indication of the potential of the generation fleet to meet demand in the system at all times and under varying scenarios.

40 The sector inquiry has shown that a clear majority of public authorities expect reliability problems in the future even though today such problems have been extremely rare in the past five years. In nine out of ten Member States, no such problems have occurred at all. The only exception is Italy, where such issues have arisen on the islands of Sardinia and Sicily which are not well connected to the grid on the mainland. Although the Member States do not experience reliability issues at present, many Member States are of the opinion that reliability problems are expected to arise in the coming five years.

41 In most countries, TSOs are the responsible bodies for monitoring and reporting on long-term resource adequacy. Other responsible institutions are NRAs or governments In the UK, the medium and long term resource adequacy assessments are carried out by the NRA and government respectively. In Estonia, the long term monitoring is managed by the government.

The methodologies are however rarely comparable across Member States. Methods vary significantly, for instance when it comes to the question whether to take into account generation from other countries, but also regarding the scenarios and underlying assumptions[42].

The Council of European Energy Regulators (CEER)[43] performed a survey over European countries showing that security of supply is dealt with at national level through quite different approaches:

- Assessing resource adequacy requires the definition of one or more **scenarios** that can affect generation and demand projections. These scenarios are elaborated according to different assumptions about load (typically high vs. low demand scenario), and type and amount of future installed capacity (e.g. conservative or baseline vs. high RES penetration scenario). Regarding the scenarios[44] used in the different Member States, the methodologies differ greatly depending on the targeted timeframe[45] and the majority of them do not seem to be consistent throughout most of the national resource adequacy assessments.

- Regarding **load forecast**, Member States base their projections on historical load curves, with assumptions on the evolution of specific parameters. The most exploited parameters are economic growth, temperature, policy, demography and energy efficiency. The extent to which types of consumers are grouped to appraise carefully different consumption patterns can be very different[46]. Moreover demand response is largely not included as a separate factor in load forecast methodologies, even though it may appear that it is indirectly included in the projections through the effects it has had on the historical load curves[47].

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42 JRC (2016), "Generation adequacy methodologies review"

43 CEER (2014), *"Assessment of electricity generation adequacy in European countries"*

44 In at least 6 countries (including Sweden, Romania, Malta, Finland and Norway) resource adequacy is assessed against a single pre-defined baseline scenario. For the other cases (UK, France, the Netherlands, Estonia, Hungary, Lithuania, Belgium, Spain, Ireland and Italy), several possible scenarios are considered on the basis of different assumptions about load as well as type and amount of future installed capacity, such as a conservative scenario, a baseline scenario a RES penetration scenario, for example.

45 In at least 9 countries (France, Estonia, Malta, Hungary Lithuania, Belgium, Spain, Ireland and Italy) the scenarios are compounded taking as a reference the short, medium and long-term horizons. In the Netherlands and Finland, the long term is not considered, while in Sweden and Norway only the short-term is taken into account. In Denmark, only the long-term scenario is considered. In the Czech Republic and Switzerland, the only scenario considered is the very long term, while in Spain the latter scenario completes the short, medium and long-term analyses. Finally, in Romania, no short-term analysis is performed (only mid and long-term scenarios are considered).

46 In 10 national resource adequacy reports (the UK, France, Norway, Malta, Czech Republic, Hungary, Lithuania, Ireland, Austria and Italy) more than one category of consumers (e.g. residential, industrial, commercial, agriculture, etc.) serve as a basis for the forecasts; while in 4 reports (the Netherlands, Estonia, Belgium and Sweden), load only is forecasted at an aggregate level.

47 Only 3 countries include demand response as a separate factor in their load forecast methodology i.e. the UK, France and Spain. In Norway and Finland, the contribution from demand response is not included as separate factor, but peak load estimation is based on actual load curves which include the

- Regarding **generation forecast**, the most important inputs are the information received by those intending to build new generation and rules on how to consider existing infrastructure. All Member States take projected investments into account, sometimes with very heterogeneous sources and assumptions[48]. In addition, there are also various ways generation from variable output (i.e. intermittent RES) is modelled[49]; from no consideration at all, to precise hourly estimations based on sophisticated data. It is commonly agreed that there is a need to improve methodologies to better address how variable output impacts adequacy.

- With an increasing proportion of variable renewable resources, electricity systems have become more complex. To address this increased complexity, some Member States have replaced relatively simple, 'deterministic' assessment metrics[50] – which simply compare the sum of all nameplate generation capacities with the peak demand in a single one-off moment – by more complex **'probabilistic'[51] models**, which are able to take into account a wide range of variables and their behaviour under multiple scenarios. This includes not only state of the art weather forecasts, but also factors in less predictable capacity sources such as the contribution from demand response, interconnectors or renewable energy sources.

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effect of demand response. Sweden does not consider demand response, and do not assume that consumers respond to peak load in their analysis.

48 For instance, decommissioning (and mothballing) of investments is not systematically taken into account. Most collected data come from generators, partly directly via the TSOs.

49 Some countries (Estonia, Romania, Malta and Denmark) still go with the approach of unavailable capacity while there are also others like the Netherlands, Norway, Spain and Sweden, which take a certain percentage as available generation. On the contrary, France and the UK go up to detailed modelling based on climate data, hub heights (for offshore wind farms) and detailed coordinates for the generation sites.

50 One of the simplest measures to determine the level of resource adequacy is the capacity margin. This deterministic methodology simply expresses the relation between peak demand in the electricity system and the total available supply, usually as a percentage. In only two of the eleven Member States analysed in the sector inquiry, this relatively simple capacity margin is calculated. For instance in 2016, France had 104,480 MW of production installed capacity whereas peak demand during winter 2015/2016 was 84,700 MW; from that, one could say that France has approximately a 23% capacity margin (RTE figures). Of course, no form of generation can always output its full nameplate capacity with 100% reliability. Therefore, each source of input needs to apply a de-rating factor in order to reflect its likeliness to be technically available to generate at times of peak demand (e.g. in Ofgem's electricity capacity assessment, a combined cycled gas plant is assumed to be available 85% of the time). In 2014, CEER found that 6 Member States were using de-rated capacity margins: Estonia, Malta, Hungary, Belgium, Spain and Sweden.

51 Around half of the Member States of the sector inquiry carry out a 'probabilistic' calculation that can be either expressed in LOLP, LOLE or EENS: (i) Loss of load probability (LOLP) quantifies the probability of a given level of unmet demand at any particular point in time; (ii) Loss of load expectation (LOLE) sets out the expected number of hours or days in a year during which some customer disconnection is expected. For instance, French TSO RTE expects some customer disconnection to happen during 1h45 over winter 2016-2017; (iii) Expected energy non served (EENS) measures the total shortfall in capacity that occurs at the time when there are disconnections. EENS makes it possible to monetise where VoLL has also been calculated.

Nonetheless, these adequacy methodologies[52] still differ (deterministic vs. stochastic).

- Despite on-going developments, some assessments are still considering isolated systems and/or developing ways to include interconnectors[53]. Others use non-harmonised methodologies to consider cross-border capacity, with no cross-border coordination foreseen. The availability of interconnection capacity is mostly based on historical data (export and import flows during various periods of time) and to lesser extent, on estimated data (e.g. market component such as future prices estimations). Generation and load data correlations at supranational levels are rarely considered[54], and for country-wide modelling, the "copperplate approach" prevails[55].

- It should be noted that monitoring and assessing resource adequacy is a very complex process which requires defining robust concepts, criteria and procedures in order to give a reference tool to decision-making bodies if problem are encountered. In almost all EU countries, the body responsible for ultimately ensuring resource adequacy is the national government. However, monitoring responsibilities are usually shared among the TSO, the NRA and the government. These responsibilities can evolve depending on the timeframe considered. For the medium and long-term timeframes, TSOs are the responsible bodies for monitoring and reporting in most Member States. Other responsible institutions are NRAs or governments[56]. In most cases, the assessment is carried out yearly.

52 Half of the national studies are based on a 'probabilistic' approach (the UK, France, the Netherlands, Finland, Romania, the Czech Republic, Lithuania, Belgium, Ireland, Italy) while six of them are based on a deterministic approach (Estonia, Malta, Hungary, Belgium, Spain and Sweden). Denmark uses a deterministic approach, but takes into account the outage percentage of power plants which is based on both historical observations and Monte Carlo simulations.

53 The extent to which current resource adequacy reports take the benefits of interconnectors into account varies a lot: 4 reports still model an isolated system (Norway, Estonia, Romania, and Sweden); 2 reports use both interconnected and isolated modelling (France and Belgium); 3 report methodologies are being modified to include an interconnection modelling; 9 reports simulate an interconnected system (UK, the Netherlands, Czech republic, Lithuania, Finland, Belgium and Ireland, while France and Italy use both methods).

54 It is not obvious that national resource adequacy reports generally take interactions between generation and demand profiles into account. Moreover, it seems that most reports do not consider correlated data, which could be done (for example with the use of a common correlated climate database at regional level, or a common methodology for load sensitivity to temperatures). One direct consequence is that most reports do not intend to identify the impact on security of supply of potential simultaneous severe conditions in different electricity systems.

55 In the process of assessing resource adequacy, transmission and distribution networks can be modelled in a very different manner, from a highly realistic description of the technical parameters which constrain the power flows in the system, to a simplified modelling where these networks are considered as a copperplate grid. Some systems are said not to be subject to structural internal congestions (including France and Romania).

56 In the UK, the medium and long term resource adequacy assessments are carried out by the NRA and government respectively. In Estonia, the long term monitoring is managed by the government.

Table 1: Deterministic vs probabilistic approaches to adequacy assessments

Adequacy Assessments							
Country	Y/N	Who?	What?	Country	Y/N	Who?	What?
Belgium	Y	TSO	Probabilistic assessment based on LOLE	Italy	Y	TSO	EENS, LOLE, LOLP and Capacity Margin are calculated
Denmark	Y	TSO	EENS, LOLE and LOLP	Poland	Y	TSO	Capacity Margin
France	Y	TSO	LOLE	Portugal	Y	TSO + Gov	Load Supply Index (supply/demand per hour)
Germany	Y	TSOs + NRA	Calculation of EENS, LOLE, LOLP and Capacity Margin	Spain	Y	TSO	Capacity Margin
Ireland	Y	TSOs + NRA	Probabilistic assessment based primarily on LOLE	Sweden	Y	TSO	EENS, LOLE and LOLP are measured

Source: European Commission based on replies to sector inquiry, see below for a description of capacity margin, LOLP, LOLE, and EENS

ENTSO-E carries out an EU-wide resource adequacy assessments

In addition to resource adequacy assessments carried out by Member States, there are also EU level rules foreseen by the Third Package (the Electricity Regulation) requiring ENTSO-E to carry out a medium and long-term resource adequacy assessment (so-called, Scenario Outlook and Adequacy Forecast or SO&AF) in order to provide stakeholders and decision makers with a tool to base their investments and policy decisions.

ENTSO-E is currently moving from a deterministic approach to a probabilistic approach (sequential Monte-Carlo). This evolution will be done progressively and is expected to be completely implemented by 2018. The first steps of the new methodology were carried out in the latest published report so-called SO&AF 2015.

The ENTSO-E SO&AF 2015 presents the following characteristics/ limitations[57]:

- ENTSO-E uses a deterministic assessment which calculates for each country deterministic security of supply indicators (namely 'remaining capacity' and 'adequacy reference margin') only at particular points in time (the 3rd Wednesday of each month on the 19th hour in the pan-European assessment or at national peak load time in the national assessments). The report presents results for the mid-term and long-term timeframes (5-year and 10 years ahead, respectively)[58].

- Regarding load forecast, there is no explicit modelling of demand-side response in the SO&AF 2015 but is expected to be taken into account from 2017 onwards.

57 JRC Science for Policy Report (2016), *"Generation adequacy methodologies review"*

58 Since 2011, ENTSO-E performs a SO&AF annually, with a time horizon of 15 years until SO&AF 2014 and 10 years in SO&AF 2015.

- Regarding generation forecast, the analysis is based on two different scenarios for generation (conservative and best estimate). The conservative scenario considers only new capacity if it is considered as certain and for the decommissioning, it considers the official notifications but also additional criteria as for example, technical lifetime of generators (additional criteria which are not considered in the best estimate scenario). RES (wind and solar PV) are taken into account for the first time in the SO&AF 2015 assessment by estimating their load factor (with a Pan-European Climate database of 14 climatic years).

- Regarding interconnection, the ENTSO-E SO&AF 2015 assessment only considers import and export capacities for each country. There is no explicit modelling of flow-based market coupling.

Voluntary initiatives to carry out regional resource adequacy assessments

Some Member States have voluntarily decided to cooperate and deliver a regional resource adequacy assessment. This is the case of the seven TSOs in the Pentalateral Energy Forum[59] ('PLEF') who have decided to move away from country specific point in time assessments to an integrated chronological probabilistic assessment. The new methodology is based on harmonised and detailed input data to capture the main contingencies[60] susceptible of threatening security of supply. This voluntary approach developed by the PLEF TSOs is currently used as a test-lab for upgrading the ENTSO-E methodology.

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[59] An inter-governmental initiative designed to promote collaboration on cross-border exchange of electricity in Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland.

[60] These contingencies include outdoor temperatures (which result in load variations, principally due to the use of heating in winter), unscheduled outages of nuclear and fossil-fired generation units, amount of water resources, and wind and photovoltaic power production.

Table 2: PLEF vs ENTSO-E approaches to adequacy assessments

	PLEF	ENTSO-E	
		Current	Targeted
Approach	Probabilistic	Deterministic	Probabilistic
Scale	Regional (at least direct neighbours, up to second degree neighbours)	National – simplified regional	Pan European
Network representation	Current (NTC[61]) and targeted (PTDF[62])	None on small scale, maximum flows on regional scale	First, NTC Later, possibly flow-based
Security of supply indicators	Loss of load (energy duration, probability, frequency,…), capacity margin	Capacity margin	Loss of load
Uncertainty considerations	Monte Carlo simulations	Additional margins	Monte Carlo simulations

Source: Artelys (2016), "METIS Study S4: Stakes of a common approach for generation and system adequacy"

5.1.3. *Deficiencies of the current legislation*

As highlighted in Section 7.3.2 of the Evaluation, resource adequacy is not addressed in the Third Package. The Commission's current tool to assess whether government interventions in support of resource adequacy are legitimate is State aid scrutiny. The EEAG require among others a proof that the measure is necessary. However, the framework does not allow the Commission to effectively judge whether there is a resource adequacy problem in the first place.

To date, the need for CMs are based on national adequacy assessments and Member States rely on them when arguying for CMs. However, national assessments are undertaken in different ways across Europe. These assumptions may substantially differ depending on the underlying assumptions made and the extent to which foreign capacities as well as demand side flexibility are taken into account in calculations. For example, the Council of European Energy Regulators (CEER) recommends to "*take into account the potential benefit provided by interconnectors in national resource adequacy analyses in a coordinated and consistent way across Member States*"[63]. In addition, CEER is of the opinion that "*these different procedures pose difficulties (especially for neighbouring countries) as it is a challenge to understand the different procedures and processes from one country to another*"[64].

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61 Interconnectors are usually modelled as commercial flows with no network physical constraints, but constrained by maximum net transfer capacities (NTC). In practice NTC values can vary quite often, due to outages, maintenance and temperature affecting lines' physical properties.

62 Power Transfer Distribution Factor

63 CEER (2014), *Recommendations for the assessment of electricity generation adequacy*

64 CEER report on *"Assessment of generation adequacy in European countries"* (published in 2014) http://www.assoelettrica.it/wp-content/uploads/2014/10/Ceer_GenerationAdequacyAssessment.pdf

Art. 8 of the Electricity Regulation gives to ENTSO-E the responsibility for carrying out a European resource adequacy outlook. It requires amongst others that the European resource adequacy outlook should build on national resource adequacy outlooks prepared by each individual TSO. Consequently the ENTSO-E assessment is rather a compilation of national assessments than a genuine calculation based on raw data input. Also the applied methodology needs a review in particular with regards to the input data and the calculation method used. For example, the European Electricity Coordination Group recommends that "*The improvements in the existing ENTSO-E methodology should focus on the consistent treatment of variable RES generation and interconnectors*"[65].. In their current form and granularity they are not suitable to assess whether certain Member States are likely to face resource adequacy problems in the mid to long-term.

Further to the difference in approach, CEER highlights that "*there are also differences between the System Outlook & Adequacy Forecast (SO&AF) undertaken by ENTSO-E and the national assessments that occur due to different quality of data and a more sophisticated approach in some countries*"[66].

All in all, neither national assessments nor ENTSO-E's European resource adequacy outlook, in their current form a) appropriately inform investors, governments and the wider public of the likely development of system margins and b) allow the Commission to effectively judge whether the proposed introduction of resource adequacy measures in single Member State is justified.

5.1.4. *Presentation of the options*

Option 0 - BAU

National decision makers would continue to rely on purely national resource adequacy assessments which inadequately take account of cross-border interdependencies. In addition, due to different national methodologies, national assessments are difficult to compare.

The Commission would continue to face difficulties to validate the assumptions underlying national methodologies including ensuing claims for CMs.

Option 0+ stronger enforcement

As the current legislation foresees that national resource adequacy plans are the basis for ENTSO-E to draw up its resource adequacy assessments, stronger enforcement is not a viable option.

Some Member States (e.g. PLEF) have voluntarily decided to cooperate and deliver a regional resource adequacy assessment. However, the PLEF geographically covers only

[65] *Report of the European Electricity Coordination Group on The Need and Importance of Generation Adequacy Assessments in the European Union*, Final Report, October 2013

[66] CEER report on *"Assessment of generation adequacy in European countries"* (published in 2014) http://www.assoelettrica.it/wp-content/uploads/2014/10/Ceer_GenerationAdequacyAssessment.pdf

part of the EU electricity market and hence its role cannot go beyond that of a test-lab for upgrading the ENTSO-E methodology. Indeed, without a common methodology for all EU Member States, the Commission would continue to face difficulties to effectively judge whether the proposed introduction of resource adequacy measures in single Member States is justified.

Option 1 – Binding EU rules requiring TSOs to harmonise their methodologies for calculating resource adequacy + requiring Member States to exclusively rely on them when arguing for CMs

Option 1 would require TSOs to harmonise their methodologies for calculating resource adequacy and require Member States to exclusively rely on them when arguing for CMs. TSOs would have to cooperate to upgrade their methodologies based on probabilistic calculations, with appropriate coverage of interdependencies, availability of RES and demand side flexibility and availability of cross-border infrastructure in times of stress.

In this option, Member States would be responsible for carrying out the assessment.

Option 2 - Binding EU rules requiring ENTSO-E to provide for a single methodology for calculating resource adequacy + requiring Member States to exclusively rely on them when arguing for CMs

Option 2 would require ENTSO-E to provide for a single methodology for calculating resource adequacy and require Member States to exclusively rely on them when arguing for CMs. The ENTSO-E methodology should be upgraded based on propabilistic calculations[67] and should appropriately take into account foreign generation, RES and demand response.

In this option, Member States would be responsible for carrying out the assessment based on the ENTSO-E methodology & coordination.

Option 3 - Binding EU rules requiring ENTSO-E to carry out a single resource adequacy assessment for the EU + requiring Member States to exclusively rely on it when arguing for CMs

Option 3 would require ENTSO-E to carry out an EU-wide resource adequacy assessment and Member States to exclusively rely on it when arguing for CMs. In other words, this would mean that, ENTSO-E would be required to not only provide for the methodology (similar to Option 2) but also carry out the assessment. The ENTSO-E assessment should have the following characteristics:

i. It should cover all Member States
ii. It should have a granularity of Member State/ bidding zone level to enable the analysis of national/ local adequacy concerns;

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[67] The PLEF approach could serve as a pioneer for applying the advanced methodology for a wider perimeter.

iii. It should apply probabilistic calculations that consider dynamic characteristics of system elements (e.g. start-up and shut-down times, ramp up and ramp-down rates…)[68]

iv. It should calculate resource adequacy indicators for all countries (LOLE, EENS, etc.)

v. It should appropriately take into account foreign generation, interconnection capacity, RES[69], storage and demand response

vi. The assessment should be carried out every year

vii. Time span of 5-10 years

It should be noted that under this option each Member State would be allowed to carry out their national resource adequacy assessment if they wish to but they would not be able to rely on these results when arguing for CMs.

5.1.5. *Comparison of the options*

Contribution to policy objectives

Under **Option 0**, proposed CMs would be based on national resource adequacy assessments and projections. National assessments may substantially differ depending on the underlying assumptions made and the extent to which foreign capacities as well as demand side flexibility and variable renewable generation[70] are taken into account in calculations. Some countries even use deterministic methodologies that are obsolete (they do not consider the stochastic nature of forced outages and variable renewable generation). In addition, these national assessments are often not in line with the current EU-wide assessment carried out by ENTSO-E. All in all, this approach reinforces the national focus of most mechanisms and prevents a common view on the adequacy situation. Remaining in the *status quo* may therefore lead to significant capacity overinvestments. In consequence, it creates more uncertainty in neighbouring countries as each Member State takes individual actions in putting in place CMs.

In **Option 1**, proposed CMs would still be based on national resource adequacy assessments but these would adopt harmonised methodologies including input data. The assessments would thus become more comparable across Member States. However, even though this approach is an improvement compared to Option 0, it seems likely that Option 1 would still lead to significant capacity overinvestments. Although this option provides a minimum harmonization, the implementation time will take longer as some Member States current methodologies are far from the target one. An entity or body needs to assure that the harmonized methodology is properly implemented and check the consistency of the results across countries. This option can produce significant delays.

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[68] This means considering flexibility issues, temporal constraints and a realistic evaluation of the expected role of interconnectors.

[69] National but also foreign RES should be considered as the IEM and the interconnection capacity are the basis for a more and better integration of RES allowing a higher capacity factor for RES. The same can apply to storage.

[70] Some countries still assume zero capacity value for wind and PV. Countries that do not assume a zero value differ on the methodology to estimate the capacity value of RES.

Option 2 would make it easier to embark on a single methodology. Moreover, this approach is likely to result in less over-investment in power infrastructure. However, it would be difficult to coordinate the work of the 30+ TSOs in Europe. In addition, national TSOs might be overcautious and not take appropriately into account cross-border interdependencies. Even in the presence of a single methodology, national assessments would not be able to provide an effective regional or EU picture.[71] Indeed, national interests could still play a role in the manner in which the assessments are done. There is a risk that Member States would deviate from the single methodology when implementing it which means that an enforcement and monitoring mechanism should be provided for.

Option 3 would most likely be the best option to reach the set objectives as it would make sure that the national puzzles neatly add up to a European picture allowing for national/ regional/ European assessments. A major advantage is that ENTSO-E has already been carrying out an EU-level resource adequacy assessment based on the Union legislation. By requiring ENTSO-E to carry out the assessment, Option 3 appears to be appropriate to overcome the main obstacles that prevent Option 1 and 2 from being effective. Indeed, there would be less room for Member States to deviate in the implementation of the single methodology. This would favour neutrality as it would avoid national interests playing a role in the manner in which the assessments are done. Efficiencies would arise from a reduced need for coordination between Member States and a reduced need for oversight during the implementation of the methodology by the Member States. As a drawback, Option 3 would potentially reduce the 'buy-in' from national TSOs who might still be needed for validating the results of ENTSO-E's work. All in all, this option would best assess the capacity needs for resource adequacy and hence allow the Commission to effectively judge whether the proposed introduction of resource adequacy measures in single Member States is justified.

Key economic impacts

An expert study carried out using METIS[72] assesses the benefits of cooperation for resource adequacy. The study highlights that significant capacity savings can be obtained from a European approach to security of supply with respect to a country-level resource adequacy assessment. The reasons for these savings is that Member States have different needs in terms of capacity with peak demands that are not necessarily simultaneous. Therefore, they can benefit from cooperation in the production dispatch and in investments.

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[71] For example the extent to which Member States can rely on each other for contributions to their own security of supply depends, among other things, on the likelihood of scarcity situations occurring simultaneously in those Member States. Even if Member States calculate their resource adequacy assessment based on a single methodology it cannot be ensured that they arrive at exactly at the same outcomes except if all Member States share all data sets generated by the other and if they carry out exactly the same computational steps using those data sets.

[72] "*METIS Study S16: Weather-driven revenue uncertainty for power producers and ways to mitigate it*", Artelys (2016).

The model jointly optimises peak capacities for two reference cases for EuCO27[73] – without cooperation (capacities are optimised for each country individually, as if countries could not benefit from the capacities of their neighbours) vs. with cooperation (capacities are optimised jointly for all countries, taking into account interconnection capacities (NTCs).

In both options, capacity dimensioning has the following characteristics: (i) removal of peak fleets (CCGT, OCGT and oil) to avoid excessive overcapacity); (ii) Other units are kept (including nuclear, coal and lignite), which creates overcapacity for CZ, SK and BG; (ii) Optimisation of gas and peak fleats (modeled as OCGT) with VOLL = 15k EUR/MWh and peak annual price = 60k EUR/MW/year.

The difference in installed capacity between the two cases reveals how much savings could be made from cooperation in investments.

Results show that almost 80 GW of capacity savings (see figures 2 and 3) across th EU, which represents 31% of the installed gas capacities, can be saved with cooperation in investments. This represents a gain of EUR **4.8 billion per year** of investments.

It should be noted that this figure does not assess at which stage Member States are currently (i.e. whether some Member States already benefit from the capacities of their neighbours), as the benefits have already been reaped by some. It should also be noted that **this figure does not include savings on production dispatch**, which could lead to much higher monetary benefits.

[73] The scope of the model comprises EU28 + (CH, NO, BA, MK, ME, RS) and 50 years of weather data.

Figure 2 – Capacity savings for METIS EuCO27 in GW

Zone	Capacity savings (in GW)
EU28	79
AT	3
BE	2
BG	0
CY	0
CZ	0
DE	14
DK	2
EE	0
ES	3
FI	3
FR	10
GR	3
HR	1
HU	2
IE	1
IT	6
LT	0
LU	1
LV	1
MT	0
NL	7
PL	6
PT	2
RO	3
SE	6
SI	0
SK	0
UK	4

Source: METIS

Figure 3 – Capacity savings for METIS EuCO27 in % of demand

Source: METIS

The main reasons for these capacity savings are twofold: (i) variability of peak demand across Europe and (ii) variability of weather conditions (and consequently of RES generation profiles) across Europe.

- Variability of power demand profiles across Europe: Energy end use practices are different and the deployment of equipement using electricity (for instance electrical heating) varies across Member States. In particular, the sensitivity of Member States national demand with regards to temperature varies from one country to the other. Moreover, low temperature events do not occur at the same time in all Member States[74]. As a consequence, the aggregated European demand peak is lower than the sum of all national demand peaks (which do not occur at the same time). A European electric system with cooperation in capacity dimensioning would therefore face a lower capacity need – defined by the aggregated European demand peak – than a set of isolated national systems,

[74] For instance, extreme temperature conditions are often not correlated between Western Europe and Northern Europe (Norway, Sweden, Finland and Estonia).

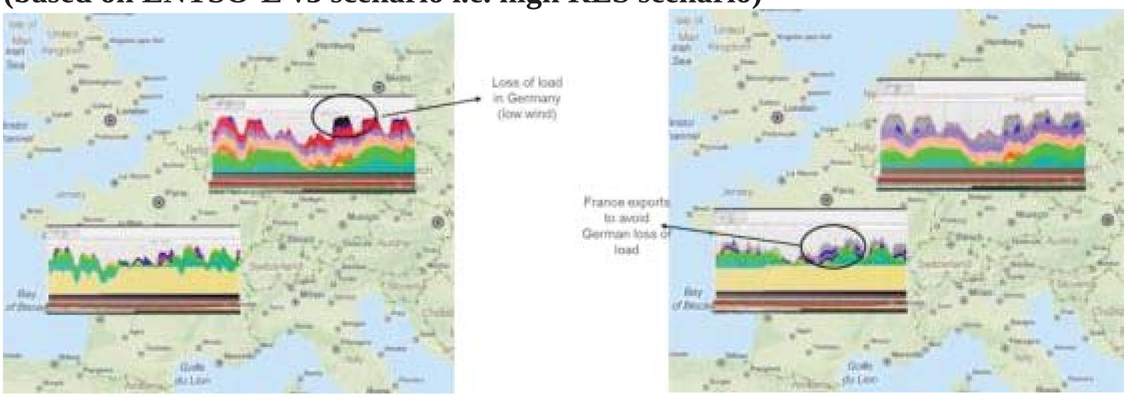
which would require a global generation capacity as high as the sum of national peak demand.

Figure 4 – illustration of cooperation in variability of peak demand across Europe (based on ENTSO-E v3 scenario)

Source: METIS

- Variability of RES generation profiles: Despite geographical correlations at the regional scale, different climatic regimes produce different weather conditions across Europe, which often compensate one another. This influences the RES generation profiles. Indeed, aggregating European RES generation profiles leads to higher load factors for RES than single country RES load factors.

Figure 5 – illustration of cooperation in variability of RES generation across Europe (based on ENTSO-E v3 scenario i.e. high RES scenario)



Source: METIS

Impact for businesses and public authorities

The **administrative costs**[75] are expected to be marginal compared to the economic benefits that would be reaped. ENTSO-E currently employs two FTEs to carry out its resource adequacy assessment and has a working group of 10 FTEs from national TSOs. In addition, we assume approximately 100 FTEs working on national resource adequacy

[75] The economic costs linked to resource adequacy assessments are based on own estimations, resulting from discussions with stakeholders and experts.

assessments in TSOs across Europe (Option 0). Option 1 is assumed to require require 20-25 additional FTEs for coordinating the harmonisation of national assessments. It is likely that Option 2 would be slightly less human intensive – only 15-20 additional FTEs would be needed. Under Option 3, it is assumed that the same amount of FTEs would be needed as in Option 2 but these would be employed by ENTSO-E. In monetary terms, this can be translated into 2-3 million euros annually in terms of personnel costs for Option 3. In addition, IT costs are equally likely to be small. For Option 3, IT costs are assumed to be in the range from 2-3 million euros per year as ENTSO-E would need more calculatory power that has IT implications. For options 1 and 2, they are likely to be lower than for Option 3 as TSOs across Europe have already developed their own IT systems. All in all, the estimated administrative costs of ENTSO-E providing for a single methodology and carrying out the assessment (Option 3) would range from **4 to 6 million euros per year.** This is marginal compared to the estimated benefits presented above.

Table 3: Comparison of the Options in terms of their effectiveness, efficiency and coherence of responding to specific criteria

	Option 0: No further action	**Option 1**: Harmonisation of national assessments	**Option 2:** ENTSO-E provides for single methodology, Member States carry out the assessment	**Option 3:** ENTSO-E provides for single methodology and carries out the assessment
Quality of the methodology	-- No progress or uncertain progress as it depends on Member State independent initiatives	0 Progress remains limited as only harmonisation	++ Efficient as there is a single methodology	++ Coherence as ENTSO-E runs the same model for all Member States and the pan-European assessments. Input and output data are more coherent.
Use of established institutional processes	- Unclear which processes to be used	+ Can build upon established processes	0/+ Can partially build upon established processes	- Requires building up new processes (ENTSO-E to carry out the assessment)
Efficient organisational structure	- Each Member State carries out its own assessment	- Each Member State carries out its own assessment	0/- Each Member State carries out its own assessment based on ENTSO-E methodology	++ Efficient as ENTSO-E carries out the assessment for all Member States
Capacity savings	-- Low capacity savings	- Higher capacity savings due to different treatment of cross-border capacity	+ Higher capacity savings as single methodology	++ Highest capacity savings as single methodology and calculation

The assumptions are based on the Market Design Initiative consultations and other meetings with stakeholders

In summary:

- Option 0, "No further action": will likely lead to significant over-investments and hence will fall short in providing the adequate level of security of supply for Europe for any given provision cost level.
- Option 1, "Harmonisation of national assessments": is likely to be more efficient than Option 0, but cannot be expected to fully meet the specific objectives.
- Option 2, "ENTSO-E providing for a single methodology but Member States carrying out the assessments": is likely to lead to less overinvestment. Nonetheless, national interests could still play a role in the way in which the assessments are done.
- Option 3, "ENTSO-E providing for a single methodology and carrying out the assessments": seems, according to the assessment of the options, to be the most appropriate measure for assessing generation adequacy assessment.

5.1.6. *Subsidiarity*

The **subsidiarity** principle is fulfilled given that the generation adequacy challenges the EU power system is facing cannot be optimally addressed based on national adequacy assessments as is currently the case, as foreign contribution to national demand might not be sufficiently taken into account. This can be the case because national assessments apply different assumptions, calculatory approaches and data input. This is why it would be best suited to require ENTSO-E to carry out a single updated generation adequacy assessment for the EU based on a revamped methodology and high quality and granular data input from TSOs including requiring Member States to exclusively rely on it when arguing for CMs.

Requiring ENTSO-E to carry out a single generation adequacy assessment for the EU would also be in line with the **proportionality** principle given that the total capacity requirements for ensuring the same level of security of supply will be lower than in the case of national adequacy assessments. This will strengthen the internal market by making sure that resources are deployed and utilised efficiently across the EU.

5.1.7. *Stakeholders' opinions*

Replies to the public consultation on the Market Design Initiative

A majority of stakeholders (34%) is in favour of sticking to an "**energy-only**" market, possibly with a strategic reserve. Many generators and some governments disagree and are in favour of market-wide CMs (in total 22% of stakeholders replies). Many stakeholders (31%) share the view that properly designed energy markets would make capacity mechanisms redundant (21% disagree).

There is almost a consensus amongst stakeholders on the need for a more aligned method for **generation adequacy assessment** (73% in favour, 2% against). A majority of answering stakeholders (47% of all stakeholders) supports the idea that any legitimate claim to introduce CMs should be based on a common assessment. When it comes to geographical scope of the harmonized assessment a vast majority of stakeholders (86%) call for regional or EU-wide adequacy assessment while only a minority (20%) favour a national approach.

Most of the stakeholders including Member States agree that a regional/European framework for CMs are preferable. Member States, however, might want to keep a large degree of freedom when proposing a CM. They might claim that beyond a revamped regional/ EU generation adequacy assessment there is legitimacy for a national assessment based on which they can claim the necessity of their CM.

Sensibilities

The CEER claims that "*security of supply is no longer exclusively a national consideration, but it is to be addressed as a regional and pan-European issue*" and that "*generation adequacy needs to be addressed and coordinated at regional and European* *level in order to maximise the benefit of the internal market for energy*". As a conclusion to their survey, the CEER published recommendations[76] that emphasize the need for the implementation of a single harmonised methodology. The PLEF has already used such a common approach in a recent security of supply study[77]. In addition, ENTSO-E's target methodology is announced to be "*fully in line with the methodology developed by the TSOs of the PLEF*"[78].

EFET[79] is of the opinion that "*the current 'national approach' potentially leads to an over procurement of capacity as Member States do not appropriately take into account what capacity is available outside of their borders. As a medium step, regional assessments based on clusters of countries that are highly interconnected can be efficient, as they will effectively pool resources over a wider area. The ENTSO-E SO&AF reports are a first step in the direction of a European approach to adequacy assessment. However, the reports so far only consolidate the analysis of individual TSOs for their respective control area/country. Market participants still expect a truly European adequacy assessment from ENTSO-E, and national regulators should support the requests of ACER and the European Commission in that regard.*"

On the ENTSO-E methodology, Wind Europe[80] is of the opinion that "*most national adequacy assessments focus on the contribution of firm generation units, with little or no consideration for the contribution of other energy sources such as demand-side response, storage, imports/exports or renewables.*" It recommends that "*developing a holistic approach that systematically and realistically include renewables, demand response, storage and interconnections' contribution to adequacy."*

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76 Recommendations for the assessment of electricity generation adequacy, CEER

77 Pentalateral Energy Forum [PLEF] – Support Group 2, Generation Adequacy Assessment

78 Energy Community Workshop: "*Towards Sustainable Development of Energy Community*", RES integration: the ENTSO-E perspective

79 EFET answer to the public consultation on the market design initiative

80 Wind Europe, "Assessing resource adequacy in an integrated EU power system" (May 2016)

5.2. Cross-border operation of capacity mechanisms

5.2.1. *Summary table*

Objective: Framework for cross-border participation in capacity mechanisms			
	Option 0	**Option 1**	**Option 2**
Description	Do nothing. No European framework laying out the details of an effective cross-border participation in capacity mechanisms. Member States are likely to continue taking separate approaches to cross-border participation, including setting up individual arrangements with neighbouring markets.	Harmonised EU framework setting out procedures including roles and responsibilities for the involved parties (e.g. resource providers, regulators, TSOs) with a view to creating an effective cross-border participation scheme.	Option 1 + EU framework harmonising the main features of the capacity mechanisms per category of mechanism (e.g. for market-wide capacity mechanisms, reserves, …).
Pros	Stronger enforcement The Commission's Guidance on state interventions[81] and the EEAG require among others that such mechanisms are open and allow for the participation of resources from across the borders. There is no reason to believe that the EEAG framework is not enforced. To date, however, there are not many practical examples of such cross-border schemes.	It would reduce complexity and the administrative impact for market participants operating in more than one Member States/bidding zone. It would remove the need for each Member State to design a separate individual solution – and potentially reduce the need for bilateral negotiations between TSOs and regulators. It would preserve the properties of market coupling and ensure that the distortions of uncoordinated national mechanisms are corrected and internal market able to deliver the benefits to consumers.	In addition to benefits in Option 1, it would facilitate the effective participation of foreign capacity as it would simplify the design challenge and would probably increase overall efficiency by simplifying the range of rules market participants, regulators and system operators have to understand.
Cons	As the conclusion of individual cross-border arrangements depend on the involved parties' willingness to cooperate it is likely that this option will cement the current fragmentation of capacity mechanisms. Arranging cross-border participation on individual basis is likely to involve high transaction costs for all stakeholders (TSOs, regulators, ressource providers).	It would be a cost for TSOs and regulators which would have to agree on the rules and enforce them across the borders. These costs would be lower than in Option 0 though.	In addition to the drawback of Option 1, it would limit the choice of instruments.
Most suitable Option(s): Options 1 and 2			

[81] http://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd01_en.pdf

5.2.2. *Description of the baseline*

DG COMP's sector enquiry on Capacity Mechanisms found that cross-border participation is not yet enabled in the majority of CMs, and with different Member States developing different solutions for their already different national capacity mechanisms there is an emerging risk of increasing fragmentation in the market.

The exclusion of foreign capacity from CMs reduces the efficiency of the internal market and increases costs for consumers. The most damage is done if Member States make no assessment of the possibility of imports when setting the amount of capacity to contract through a CM (in a volume-based model) or setting the price required to bring forward the required volume (in a price-based mechanism). In this approach (**no cross-border participation**), there would be greater distortion of the signals for where new capacity should be built, and an increase in overall system costs due to overcapacity. In addition, CMs would fail to adequately reward investment in interconnection that allows access to capacity located in neighbouring markets. The potential unnecessary costs of this overcapacity has been estimated at up to 7.5 billion euros per year in the period 2015-2030[82].

Some Member States have attempted to address the problem by taking account of expected imports (at times of scarcity) when setting the volume to contract in their capacity mechanism (defined as **implicit participation**) This reduces the risk of domestic overprocurement and recognises the value to security of supply of connections with the internal energy market. However, implicit participation does not remunerate foreign capacity for the contribution it makes to security of supply in the CM zone. If only domestic capacity recieves capacity payments, there will be a greater incentive for domestic investment than investment in foreign capacity or interconnectors resulting in less than optimal investment in foreign capacity and in interconnector capacity.

The best approach to this would be **explicit participation** which means that the contribution of imports to the CM zone must not only be identified, but the providers of this foreign capacity need to be remunerated for the security of supply benefits that they deliver to the CM zone.

This approach has been formalised in the Commission's Guidance on state interventions[83] and the EEAG which require among others explicit participation of foreign capacity in the CM (EEAG 232).

However, putting in place a functioning explicit cross-border CM requires multiple arrangements involving several parties (e.g. resource providers, TSOs, regulators). This is a difficult exercise requiring willingness and cooperation from all parties which cannot

82 See Booz & co, 2013, *'Study on the benefits of an integrated European Energy market'*
83 http://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd01_en.pdf

be taken for granted. This could explain why, to date, there are not many practical examples of such cross-border schemes.

Member States who have implemented an explicit cross-border scheme have taken different approaches. Portugal, Spain and Sweden appear to take no account of imports when setting the amount of capacity to support domestically through their CMs. In Belgium, Denmark, France and Italy, expected imports are reflected in reduced domestic demand in the CMs. The only Member States that have allowed the direct participation of cross-border capacity in CMs are Belgium, Germany and Ireland.

Foreign plants were allowed to participate in the Belgian tender for new capacity, provided that they would subsequently become part of the Belgian bidding zone even if geographically located in another Member State.

In the Irish tender, foreign capacity could participate if it could demonstrate its contribution to Irish security of supply – no foreign capacity was selected in the tender. In the existing Irish capacity payments model, foreign capacity can benefit from capacity payments. However, the method for enabling this participation involves levies and premiums on electricity prices and is not therefore compatible with market coupling rules which require electricity prices, not capacity premiums/taxes, to provide the signal for imports and exports[84].

None of the strategic reserves are open to generators located outside of the Member State operating the reserve mechanism; except for the German network reserve which contracts capacity outside of Germany provided that it can contribute to alleviating security of supply problems in Southern Germany through re-dispatch abroad.

Despite the current lack of foreign participation, many Member States are trying to develop cross-border participation in their mechanisms. France carried out last year a consultation which outlined different options for the participation of interconnectors or foreign capacity in the decentralised obligation scheme. Ireland published a consultation in December[85] on options for cross-border participation in its planned mechanism. Italy is apparently considering future foreign participation in its capacity mechanism. Since December 2015 the British capacity mechanism has included interconnectors with Britain, which can participate as price takers in capacity auctions.

5.2.3. *Deficiencies of the current legislation*

The Commission's current tool to assess whether government interventions in support of generation adequacy are legitimate is State aid scrutiny. The EEAG require among others a proof that the measure is necessary, technological neutral and allows for explicit cross-border participation. Beyond the requirements of the Commission's guidance on state intervention and the EEAG, there is no European framework laying out the details of an effective cross-border participation in capacity mechanisms.

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[84] Note however that the Irish capacity mechanism does operate across the UK and Irish border because of joint market arrangements and a single bidding zone covering Ireland and Northern Ireland.

[85] https://www.semcommittee.com/overview?article=f254d505-16bc-4a66-b940-bf2cc7b614ae

This could explain why few Member States have developed cross-border schemes with explicit participation, which means that (at best) they only **implicitly** take into account foreign capacities. If Member States limit participation in a national mechanism only to capacity providers located within their borders, and make overly conservative assumptions about their level of imports they should expect, this will lead to distorted locational investment signals and over-capacity in areas with capacity mechanisms. These distortions can benefit incumbent market participants which will further reduce competition in the long run.

Member States wanting to comply with the EEAG requirements have to individually arrange, for each of their borders separately, the necessary cross-border arrangements involving a multitude of parties including regulators, resource providers and TSOs. Arranging cross-border participation on individual basis is likely to involve high transaction costs for all stakeholders. This is also a difficult exercise requiring willingness and cooperation from all parties which cannot be taken for granted.

When developing solutions for explicit participation of interconnectors and foreign capacity to their CM, Member States need to address a number of policy considerations. For example, an explicit participation model needs to identify:

- Whether there should be any restriction on the amount of capacity that can participate from each connected bidding zone;
- What type of capacity product (obligations and penalties) should apply to foreign capacity providers; and
- Which foreign capacity providers are eligible to participate (DSR, generation, storage).

It is therefore not surprising that 85% of market participant respondents and 75% of public body respondents to the sector inquiry questionnaire felt that rules should be developed at EU level to limit as much as possible any distortive impact of CMs on cross national integration of energy markets.

The fact that cross-border participation is not yet enabled in the majority of CMs as highlighted on p.30 of the Evaluation, and with different Member States developing different solutions for their already different national CMs, there is an emerging risk of increasing fragmentation in the market.

5.2.4. *Presentation of the options*

Option 0 - BAU

The Commission's Guidance on state interventions[86] and the EEAG require among others that such mechanisms are open and allow for the participation of resources from across the borders.

[86] http://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd01_en.pdf

The EEAG include the following requirements related to cross-border participation in a generation adequacy measure:

i. Should take the contribution of interconnection into account (226);
ii. Should be open to interconnectors if they offer equivalent technical performance to other capacity providers (232)
iii. Where physically possible, operators located in other members states should be eligible to participate (232);
iv. Should not reduce incentives to invest in interconnection, nor undermine market coupling (233).

As explained above, the EEAG requires among others explicit participation of foreign capacity in the capacity mechanism (EEAG 232). However, Option 0 does not provide for a European framework setting out harmonised rules of an effective cross-border participation scheme.

Option 0+

Despite the EEAG requirements for Member States to individually arrange, for each of their borders separately, the necessary cross-border arrangements, few Member States have voluntraily collaborated to develop an effective cross-border scheme. This is a difficult exercise requiring willingness and cooperation from all parties which cannot be taken for granted.

Option 1 - Harmonised EU framework setting out procedures including roles and responsibilities for the involved parties (e.g. resource providers, regulators, TSOs) with a view to creating an effective cross-border participation scheme

Under this option there would be a requirement for Member States to allow for explicit participation of foreign capacity in national CMs.

There would also be a harmonised EU framework setting out procedures including roles and responsibilities for the involved parties (e.g. resource providers, regulators, TSOs) with a view to creating an effective cross-border participation scheme. The framework would:

a) Define the appropriate share of foreign participation (de-rating of resources);
b) Allocation of 'entry tickets' to foreign resource providers[87];

[87] The contribution foreign capacity makes to a neighbour's security of supply is provided partly by the foreign generators or demand response providers that deliver electricity, and partly by the transmission (interconnection) allowing power to flow across borders. Depending on the border, there can be a relative scarcity of either interconnection or foreign capacity. To ensure the right investment incentives, the revenues from the mechanisms paid to the interconnection and/or the foreign capacity should reflect the relative contribution each makes to security of supply in the zone operating the CM. Where interconnection is relatively scarce but there is ample foreign capacity in a neighbouring zone, the interconnectors should thus receive the majority of CM. This would reinforce incentives to invest in additional interconnection, which is the limiting factor in in this case. Conversely, where there is ample interconnection but scarcity of foreign capacity, the foreign capacity should receive most of the

c) Same remuneration principles for domestic and foreign resource providers;
d) No booking (or setting aside) of cross-border capacities for cross-border participation;
e) Contribution of foreign capacity in parallel scarcity situations[88] to be addressed by de-rating factors;
f) No delivery obligation (only availability);
g) No adjustment of cross-border schedules;
h) No limitation of the participation of a capacity resource to a single CM where the resource can contribute to security of supply in more than one CM zone.

More details regarding the harmonised EU framework

De-rating of resources: De-rating of interconnectors and/or foreign capacity refers to an evaluation of the expected actual contribution of a capacity provider on average, over the long-term, at times when it is required. This issue is critical as conservative assumptions will lead to overcapacity, and overly generous assumptions will potentially lead to unmet demand (and potentially reduced confidence in the value of interconnection).

Entry-tickets to foreign resource providers: Foreign capacity providers would have to acquire specific "interconnection tickets" to allow them to explicitly participate in the CM. Foreign capacity bids to get access to the capacity market via the interconnection, up to the level of available interconnection capacity. The interconnection receives revenues from "interconnection tickets" auctioning. Foreign capacities receive revenues at "local CM" clearing price. This would allow a priori a market-based split of value and the right incentive for investments.

Same remuneration principles for domestic and foreign resource providers: In principle, if the allocation process for capacity contracts allows interconnector or foreign capacity to compete directly with domestic capacity, the obligation and penalties faced by the interconnector or foreign capacity providers should be the same as the obligations and penalties faced by the domestic capacity providers.

No booking of cross-border capacity for cross-border participation: One of the basic features of capacity mechanisms is that the participating resources (mainly generators) receive a payment for their availably in times of expected system stress. Whether a participating resource actually generates electricity depends on short-term market price signals (effectively intra-day and balancing market prices). This mechanism makes sure that power flows to the area in Europe that needs it most. For example, if short-term prices in Belgium turn out to be 2.000 EUR/MWh while prices around Belgium are only 250 EUR/MWh the market coupling algorithm (and successive intra-day exchanges) will make sure that all available transmission capacities on the Belgian border will be used to flow power into the country. The limiting factor to supply Belgium in times of stress is (most likely) not the availability of generating assets in Europe but the relative scarcity of transmission capacities towards Belgium. Setting aside transmission capacities for the purposes of cross-border participation will therefore not improve the security of power supplies in Belgium but will only interfere with the efficient functioning of power markets. Participation of resources from across the border should therefore not be link to the effective delivery of electricity from

capacity remuneration. In this case, foreign capacity is the limiting factor that should receive additional incentives.

88 The extent to which an interconnector can reliably provide imports to the countries it connects depends not just on the line's technical availability but also on the potential for concurrent scarcity in the connected markets. If zone A only has a winter peak demand problem and connected zone B only has a summer peak demand problem, each may expect 100% imports from the other at times of local scarcity. However, if countries A and B are neighbours with similar demand profiles and some similar generation types, there may be some periods of concurrent scarcity where neither can expect imports from the other.

that resource. Paying for capacity (availability) across the borders can still make sense as this provides incentives to keep resources available to produce if market prices signal so.

Contribution of foreign capacity in parallel scarcity situations to be addressed by de-rating factors: In practice, it is extremely unlikely that scarcity events will be perfectly correlated between two neighbouring countries. So, to avoid a situation where overall less contribution by imports to security of supply is assumed than is truly the case, a statistical judgement – de-rating of the interconnectors on each border to reflect expected long-run average import capacity at times of scarcity – is needed for each capacity mechanism. The amount of capacity demanded domestically should be reduced by this amount, and this capacity is then available for allocation to foreign capacity providers.

No delivery obligation (only availability): An availability cross-border product allows the internal market to function unimpeded and avoids creating distortions to merit order dispatch that might be created with delivery obligations. Moreover, an availability product provides an additional incentive for Member States to correct regulatory failures and ensure their electricity prices reflect scarcity – which has further benefits for market functioning as such prices provide a signal for investment in flexible capacity and enable demand response. Lastly, establishing a relatively simple availability product – along with other common rules – makes cross-border participation much more readily implementable.

No adjustment of cross-border schedules: Because of the potential for delivery obligations to create distortions in neighbouring markets and the fact that anyway such obligations can only incentivise actions which are likely to have a very limited effect on cross-border flows, delivery obligations are not appropriate for interconnectors or foreign capacity.

No limitation of the participation of a capacity resource to a single CM where the resource can contribute to security of supply in more than one CM zone: Without this requirement explicit participation is likely to lead to overcapacity which would be a worse outcome than implicit participation.

Option 2: – Option 1 + EU framework harmonises the main features of the capacity mechanisms per category of mechanism (e.g. for market-wide capacity mechanisms, reserves, …)

In addition to Option 1, the EU framework would harmonise the main features of the capacity mechanisms per category of mechanism (e.g. for market-wide capacity mechanism, reserves, etc.), such as the properties of capacity product to be offered, the duration of the obligation, etc.

5.2.5. *Comparison of the options*

Contribution to policy objectives

Option 0 already requires explicit participation of foreign capacity in the CM under the EEAG rules. However, the EEAG framework does not set out harmonised rules of an effective cross-border participation scheme. This explains why few Member States have developed cross-border schemes with explicit participation, which means that (at best) they only implicitly take into account foreign capacities. If Member States limit participation in a national mechanism only to capacity providers located within their borders, and make overly conservative assumptions about their level of imports they should expect, this will lead to distorted locational investment signals and over-capacity in areas with capacity mechanisms, and an increase in overall system costs. As the conclusion of individual cross-border arrangements depend on the involved parties' willingness to cooperate it is likely that this option will cement the current fragmentation of capacity mechanisms. Arranging cross-border participation on individual basis for each of a Member States borders is likely to involve high transaction costs for all stakeholders (TSOs, regulators, ressource providers). This is also a difficult exercise requiring willingness and cooperation from all parties which cannot be taken for granted.

Option 1 would facilitate explicit cross-border participation as already required by EEAG by providing an EU framework with roles and responsibilities of the involved parties. This option would remove the need for each Member State to design a separate individual solution – and potentially reduce the need for bilateral negotiations between TSOs. It would also reduce complexity and the administrative impact for market participants operating in more than one zone. Hence, it is likely that an increased number of Member States would implement an effective cross-border scheme. Explicit participation would lower overall system costs as it corrects investment signals and enables a choice between local generation and alternatives. On one hand, the capacity in a CM zone will bid lower into the domestic CM as a result of access to revenues from electricity and capacity in neighbouring zones. On the other hand, this will lead to more investment in capacity in a non-CM zone, and in transmission to neighbouring CM zones, if capacity in a non-CM zone has access to neighbouring capacity and energy prices. All in all, with the design options of an EU framework chosen above, Option 1 is likely to better preserve operational market efficiencies (e.g. market coupling) and ensure that the investment distortions of uncoordinated national mechanisms are corrected and the internal market able to deliver the benefits to consumers.

Option 2 would facilitate the effective participation of foreign capacity as it would simplify the design challenge and would probably increase overall efficiency by simplifying the range of rules market participants, regulators and system operators have to understand. At the same time there is a risk that it would limit the choice of instruments and potentially the ability to answer a wider range of problems that capacity mechanisms could address.

Key economic impacts

The economic impacts of the different options are analysed in the core document "Section 6 - Problem Area II".

Impact for businesses and public authorities

Although the cost of designing cross-border participation in CM depends to some extent on the design of the CMs, an expert study[89] estimated that such cost corresponds roughly to 10%[90] of the overal cost of the design of a CM[91]. In addition, they estimate costs associated with the operation of a cross-border scheme i.e. additional costs if cross-border participation is facilitated to amount to 6-30 FTEs[92] for TSOs and regulators combined. TSOs and regulators have to check pre-qualification and registration

89 Thema (2016), *Framework for cross-border participation in capacity mechanisms (First interim report)*

90 Costs in the design phase are one-time costs.

91 The same expert study also found that the overall cost of of the design are fairly small compared to the overall cost of the CM (remuneration of the participation ressources).

92 FTEs in other phases refer to (annually) recurring costs.

(eligibility phase) and ensure compliance i.e. monitoring, control, penalties (control/ compliance phase).[93] Market participants participating in a cross-border scheme would potentially have additional costs of 0-3 FTEs.

The expert study found that providing for a common framework for cross-border participation (Option 1) would actually reduce the cost of cross-border participation when compared with Option 0. This is because in Option 0 cross-border arrangements have to be set up and operated based on indivdual arrangements which involve costs that can be saved if these arrangements follow a template. For TSOs and NRAs, the study estimates the cost saving for Option 1 to be 30% of eligibility costs and compliance costs compared to Option 0.

In analogy to Option 1 we would expect that providing for a common template for capacity mechanisms (Option 2) would actually reduce the design cost of CMs when compared with Option 0 and Option 1. This is because in Option 0 and Option 1 CMs are designed individually which involve costs that can be saved if the CM design follows a template. For TSOs and NRAs, the study estimates the cost savings to be 50% of eligibility costs and compliance costs compared to Option 0.

[93] There is a difference between a generator model for cross-border participation and an interconnector model in relation to the costs. This difference can be explained by the number of participants and jurisdictions. The more participants and countries participate, the greater the potential for increased costs.

Table 1: Comparison of the Options in terms of their effectiveness, efficiency and coherence of responding to specific criteria

	Option 0: do nothing (EEAG)	**Option 1**: EU framework for cross-border participation	**Option 2:** EU framework for cross-border participation + blueprint
Investment distortions due to uncoordinated CMs	- More chance of distorted locational signals and over-capacity in zones with CM	+ Less chance of investment distortions due to effective cross-border scheme	+ Less chance of investment distortions due to effective cross-border scheme
Overall system costs	- Higher overall system costs	+ Lower overall system costs due to reduction in CM auction price	+ Lower overall system costs due to reduction in CM auction price
Speed of implementation	- Individual XB arrangements for each border	+ Harmonised XB arrangements across the EU	+ Harmonised XB arrangements across the EU
Complexity and administrative impact	-- High administrative impact for market participants operating in more than one zone	+ Reduced complexity and administrative impact due to harmonised rules	+ Reduced complexity and administrative impact due to harmonised rules

The assumptions are based on the Market Design Initiative consultations and other meetings with stakeholders

5.2.6. *Subsidiarity*

The **subsidiarity** principle is fulfilled given that the EU is best placed to provide for a harmonised EU framework with a view to creating an effective cross-border participation scheme. Member States currently take separate approaches to cross-border participation including often not allowing for foreign participation or only implicitly taking into account foreign contribution to own security of supply. As cross-border participation in CMs requires neighbouring TSOs' and NRA's full cooperation, individual Member States might not be able to deliver a workable system or only provide suboptimal solutions.

Providing for a framework on cross-border participation in capacity mechanisms would be also in line with the **proportionality** principle given that it aims at preserving the properties of market coupling and ensuring that the distortions of uncoordinated national mechanisms are corrected and the internal market is able to deliver the benefits to consumers. At the same time, it removes the need for each Member State to design a separate individual solution – and potentially reducing the need for bilateral negotiations between TSOs and NRAs.

5.2.7. *Stakeholders' opinions*

Public consultation on the Market Design Initiative

Stakeholders clearly support a common EU framework for **cross-border participation** in capacity mechanisms (52% in favour, 10% against). Most of the stakeholders including Member States agree that a regional/European framework for CMs are preferable. Similarly, Member States might instinctively want to rely more on national assets and favour them over cross-border assets. It is often claimed that in times of simultaneous stress, governments might choose to 'close borders' putting other Member States who might actually be in bigger need in trouble.

Sensibilities

EFET[94] is of the opinion that "*Member States with a CM need to explicitly take into account the contribution of foreign capacities. This will likely require advanced TSO-TSO cooperation, and will require more complex arrangement at EU or regional level. EFET therefore supports the establishment of EU rules in this domain. One note of caution though: in no case should the cross-border participation to national CMs result in any reservation of cross-border transmission capacity or alteration of cross-border flows from the market outcomes*".

Wind Europe[95] "*acknowledges the need for a common set of indicators and criteria for cross-border participation, as this is a necessary condition for the existence of capacity markets where needed.*" […] In addition, they "*call for a strong involvement of the Commission to ensure that such a common European framework for cross-border participation does not serve as a pretext for introducing potentially unneccesary CMs.*"

ACER and CEER[96] "*fully endorse that explicit participation of foreign capacity providers into national CMs through a market-based mechanism should be allowed. In this respect,* […] *a few important prerequisites need to be fulfilled to make explicit cross-border participation possible and beneficial: a) TSOs are incentivised to make a sufficient and appropriate amount of cross-border capacities available for cross-border trade throughout the year(s); b) TSOs are not allowed to adjust, limit or reserve these cross-border transmission capacities at any point in time, including in case of shortage situation; and c) TSOs agree ex ante on the treatment of local/ foreign adequacy providers in case of a widespread shortage situation (i.e. when a shortage situation affects at least two countries simultaneously).*"

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94 EFET response to the public consultation on the Market Design Initiative, 2015
95 WindEurope response to the public consultation on the Market Design Initiative, 2015
96 ACER-CEER response to European Commission Capacity Mechanism Sector Inquiry, July 2016

EUROPEAN
COMMISSION

Brussels, 30.11.2016
SWD(2016) 410 final

PART 5/5

COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT

Accompanying the document

Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast)

Proposal for a Regulation of the European Parliament and of the Council on the electricity market (recast)

Proposal for a Regulation of the European Parliament and of the Council establishing a European Union Agency for the Cooperation of Energy Regulators (recast)

Proposal for a Regulation of the European Parliament and of the Council on risk preparedness in the electricity sector

{COM(2016) 861 final}
{SWD(2016) 411 final}
{SWD(2016) 412 final}
{SWD(2016) 413 final}

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6. DETAILED MEASURES ASSESSED UNDER PROBLEM AREA III: A NEW LEGAL FRAMEWORK FOR PREVENTING AND MANAGING CRISES SITUATIONS

6.1.1. *Summary table*

	Objective: Ensure a common and coordinated approach to electricity crisis prevention and management across Member States, whilst avoiding undue government intervention				
	Option 0: Do nothing	**Option 0+: Non-regulatory approach**	**Option 1: Common minimum EU rules for prevention and crisis management**	**Option 2: Common minimum EU rules plus regional cooperation, building on Option 1**	**Option 3: Full harmonisation and full decision-making at regional level, building on Option 2**
Assessments	Rare/extreme risks and short-term risks related to security of supply are assessed from a national perspective. Risk identification & assessment methods differ across Member States.	This option was disregarded as no means for enhanced implementing of existing acquis nor for enhanced voluntary cooperation were identified	Member States to identify and assess rare/extreme risks based on common risk types.	ENTSO-E to identify cross-border electricity crisis scenarios caused by rare/extreme risks, in a regional context. Resulting crisis scenarios to be discussed in the Electricity Coordination Group. Common methodology to be followed for short-term risk assessments (ENTSO-E Seasonal Outlooks and week-ahead assessments of the RSCs).	All rare/extreme risks undermining security of supply assessed at the EU level, which would be prevailing over national assessment.

Plans	Member States take measures to prevent and prepare for electricity crisis situations focusing on national approach, and without sufficiently taking into account cross-border impacts. No common approach to risk prevention & preparation (e.g., no common rules on how to tackle cybersecurity risks).		Member States to develop mandatory national Risk Preparedness Plans setting out who does what to prevent and manage electricity crisis situations. Plans to be submitted to the Commission and other Member States for consultation. Plans need to respect common minimum requirements. As regards cybersecurity, specific guidance would be developed.	Mandatory Risk Preparedness Plans including a national and a regional part. The regional part should address cross-border issues (such as joint crisis simulations, and joint arrangements for how to deal with situations of simultaneous crisis) and needs to be agreed by Member States within a region. Plans to be consulted with other Member States in the relevant region and submitted for prior consultation and recommendations by the Electricity Coordination Group. Member States to designate a 'competent authority' as responsible body for coordination and cross-border cooperation in crisis situations. Development of a network code/guideline addressing specific rules to be followed for the cybersecurity. Extension of planning & cooperation obligations to Energy Community partners	Mandatory Regional Risk Preparedness Plans, subject to binding opinions from the European Commission. Detailed templates for the plans to be followed. A dedicated body would be created to deal with cybersecurity in the energy sector.
Crisis management	Each Member State takes measures in reaction to crisis situations based on its own national rules and technical TSO rules. No co-ordination of actions and measures beyond the technical (system operation) level. In particular, there are no rules on how to coordinate actions in simultaneous crisis situations between adjacent markets. No systematic information-sharing (beyond the technical level).		Minimum common rules on crisis prevention and management (including the management of simultaneous electricity crisis) requiring Member States to: (i) not to unduly interference with markets; (ii) to offer assistance to others where needed, subject to financial compensation, and to; (iii) inform neighbouring Member States and the Commission, as of the moment that there are serious indications of an upcoming crisis and during a crisis.	Minimum obligation as set out in Option 1. Cooperation and assistance in crisis between Member States, in particular simultaneous crisis situations, should be agreed ex-ante; also agreements needed regarding financial compensation. This also inclues agreements on where to shed load, when an to whom. Details of the cooperation and assistance agreements and resulting compensation should be described in the Risk Preparedness Plans.	Crisis is managed according to the regional plans, including regional load-shedding plans, rules on customer categorisation, a harmonized definition of 'protected customers' and a detailed 'emergency rulebook' set forth at the EU level.

Montoring	Monitoring of security of supply predominatly at the national level. ECG as a voluntary information exchange platform.		Systematic discussion of ENTSO-E Seasonal Outlooks in ECG and follow up of their results by Member States concerned.	Systematic monitoring of security of supply in Europe, on the basis of a fixed set of indicators and regular outlooks and reports produced by ENTSO-E, via the Electricity Coordination Group. Systematic reporting on electricity crisis events and development of best practices via the Electricity Coordination Group.	A European Standard (e.g. for EENS and LOLE) on Security of Supply could be developed to allow performance monitoring of Member States.
Pros			Minimum requirements for plans would ensure a minimum level of preparedness across EU taking into account cyber security. EU wide minimum common principles would ensure predictability in the triggers and actions taken by Member States.	Common methodology for assessments would allow comparability and ensure compatibility of SoS measures across Member States. Role of ENTSO-E and RSCs in assessment can take into account cross-border risks. Risk Preparedness Plans consisting of a national and regional part would ensure sufficient coordination while respecting national differences and competences. Minimum level of harmonization for cybersecurity throughout the EU. Designation of competent authority would lead to clear responsibilities and coordination in crsis. Common principles for crisis management and agreements regarding assistance and remuneration in simultaneous scarcity situations would provide a base for mutual trust and cooperation and prevent unjustified intervention into market operation. Enhanced role of ECG would provide adequate platform for discussion and exchange between Member States and regions.	Regional plans would ensure full coherence of actions taken in a crisis.

Cons	Lack of cooperation in risk preparedness and managing crisis may distort internal market and put at risk the security of supply of neighbouring countries.		Risk assessment and preparedness plans on national level do not take into account cross-border risks and crisis which make the plans less efficient and effective. Minimum principles of crisis management might not sufficiently adress simultaneous scarcity situations.	The coordination in the regional context requires administrative resources. Cybersecurity here only covers electricity, whereas the provisions should cover all energy sub-sectors including oil, gas and nuclear.	Regional risk preparedness plans and a detailed templates would have difficulties to fit in all national specificities. Detailed emergency rulebook might create overlaps with existing Network Codes and Guidelines.
	Most suitable option(s): Option 2, as it provides for sufficient regional coordination in preparation and managing crsis while respecting national differences and competences.				

6.1.2. *Description of the baseline*

In the area of risk prevention and management of crisis situations the current legislation is scattered over different legal acts.

Regarding **risk assessment and preparedness**, currently Article 4 of the Electricity Directive obliges Member States to ensure the monitoring of security of supply issues. Such monitoring should, in particular, cover the balance of supply and demand, the quality and level of maintenance of the networks, as well as the measures to cover peak demand and to deal with shortfalls of one or more suppliers. This also includes the obligation to publish every two years, by 31 July, a report outlining the findings resulting from the monitoring, as well as any measures taken or envisaged to address them. Member States should submit the report to the Commission.

Additionally, **ENTSO-E** has the obligation to carry out **seasonal outlooks** (6 month – summer & winter outlooks) as required by Article 8 of the Electricity Regulation. The assessments, which follow a probabilistic generation adequacy methodology, explore the main risks identified within a seasonal period and highlighting the possibilities for neighbouring countries to contribute to the generation/demand balance in critical situations.

In terms of coordination and exchange of information among Member States, the Commission created in 2012 the **Electricity Coordination Group**[1] in the aftermath of Fukushima crisis. The Group is a platform for the exchange of information and coordination of electricity policy measures having a cross-border impact. It also should facilitate the exchange of information and cooperation on security of electricity supply including the coordination of action in case of an emergency within the Union.

The legislation on **crisis management** is set by Directive 2005/89/EC (SoS Directive), Article 42 of the Electricity Directive and, as regards technical issues, the network codes, in particular by the Network Code on Emergency and Restoration ('NC ER') which is currently in comitology for approval. In addition, also the CACM Guideline and the Guideline on System Operation (SO Guideline) set out operational procedures during crisis situations, in particular on system operation to be implemented by TSOs.

The Electricity Directive contemplates in its Article 42 the possibility for Member States to take temporary safeguard measures in the event of a sudden crisis and where the physical safety or security of persons, apparatus or installation or system integrity is threatened. Member States are obligated to notify those measures without delay to the other Member States and the Commission. Any safeguard measures taken by Member States must "*cause the least possible disturbance in the functioning of the internal market and must not be wider in scope than is strictly necessary* [...]." In taking safeguard measures "*Member States shall not discriminate between cross-border contracts and national contracts*" according to Article 4(3) of the SoS Directive.

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[1] Commission Decision of 15 November 2012 setting up the Electricity Coordination Group. OJ C353, 17.11.2012, p.2.

Table 2: Specific provisions in network codes and guidelines governing crisis prevention and management at the technical level

The **Network Code on Emergency and Restoration ('NC ER')** requires in preparation for emergency situations that the relevant Regional Security Coordinators (RSCs) ensure consistency of individual TSO System Defence Plans[2]. This includes inter-TSO information exchange, identification of threats within the capacity calculation region and identification of incompatibilities of planned measures. During emergency "*each TSO shall provide through interconnectors any possible assistance*" to its neighbours and to prepare automatic load-shedding plans to ensure stable system frequency[3]. Concerning suspension of (cross-border) market activities, TSOs can suspend the provision of cross-zonal capacity and the submission of balancing bids under the following circumstances[4]: (a) blackout state or imminent risk of a blackout state after market mechanisms are exhausted; (b) continuing market activities decreases effectiveness of restoration towards normal/alert state; (c) communication tools of TSO to facilitate market are not available. It also addresses recovery and settlement of costs related to emergency measures between TSOs and market participants, subject to assessment through NRAs[5].   The **Regulation on Capacity Allocation and Congestion Management (CACM)** addresses the firmness of cross-zonal allocated capacity in case of 'force majeure' or emergency situations. It defines 'force majeure' as unusual event which has happened, is objectively verifiable, is beyond the control of a TSO and makes it impossible for the TSOs to fulfil its obligations as set out by the CACM Guideline. According to Article 72, the event of 'force majeure' allows TSOs to curtail allocated cross-zonal capacity in coordination with other concerned TSOs. TSOs are further obliged to notify market participants which are concerned by curtailment, provide compensation and limit both consequences and duration of force majeure.   The **Guideline on System Operation (SO Guideline)** defines the operational system states of 'normal', 'alert', 'emergency' and 'restoration' in its Article 18. This provides a framework for 'remedial actions' which are used by the TSOs to manage operational security violations (Art. 20 – 23) and as an example include manually controlled load-shedding (Art. 22, paragraph 1(j)). TSOs shall prepare and coordinate their remedial actions among each other and their RSCs (Art. 21, paragraph 1(b)) and prefer remedial actions which make available the largest cross-zonal capacity (Art 21, paragraph 2(d)). Moreover, they are obliged to jointly develop a procedure for sharing costs of remedial actions (Article 76, paragraph 1(b)(v)).

Source: EU legislation

Finally, on **cybersecurity,** NIS Directive provides the horizontal framework to boost the overall level of network and information security across the EU. It imposes a set of obligations on Member States as well as on essential service providers - including the electricity, oil and gas subsectors.

6.1.3. *Deficiencies of the current legislation*

The **evaluation of Directive 2005/89/EC** (SoS Directive) has revealed the existence of numerous deficiencies in the current legal framework[6]. In first place, the evaluation concludes in the **ineffectiveness** of the SoS Directive in achieving the objectives pursued, notably contributing to a better security of supply in Europe. Whilst some of its provisions have been overtaken by subsequent legislation (notably the Third Package and

[2] See Article 6 of NC ER.
[3] See Articles 14 & 15 of NC ER.
[4] See Article 35 of NC ER.
[5] See Article 8 and 39 of NC ER.
[6] See Evaluation of the EU rules on measures to safeguard security of electricity supply and infrastructure investment (Directive 2005/89/EC).

the TEN-E Regulation), there are still regulatory gaps notably when it comes to preventing and managing crisis situations.

The evaluation also reveals that the SoS Directive intervention is no longer relevant today as **it does not match the current needs on security of supply**. As electricity systems are increasingly interlinked, purely national approaches to preventing and managing crisis situations can no longer be considered appropriate. It also concludes that its **added value has been very limited** as it created a general framework but left it by and large to Member States to define their own security of supply standard. Whilst electricity markets are increasingly intertwined within Europe, there is **still no common European framework governing the prevention and mitigation** of electricity crisis situations. National authorities tend to decide, one-sidedly, on the degree of security they deem desirable, on how to assess risks (including emerging ones, such as cyber-security) and on what measures to take to prevent or mitigate them.

The existing regulatory gap on preventing and managing crisis situations is described in detail below.

The existing obligations for the Member States on monitoring security of supply (Article 4 of the Electricity Directive and Article 7 of the SoS Directive) focus mainly on generation adequacy and **do not address the preparation for or dealing with crisis situations**. In practice, the reports submitted under Article 4 of the Electricity Directive are a mere compilation of information on supply and demand figures showing the evolution in a certain time horizon, while the lists of measures described cover mainly infrastructure projects on generation and cross-border interconnections.

There is **no legal** obligation for Member States **to carry out a risk assessment or to draw up a risk preparedness plan**[7]. All Member States set an explicit or implicit obligation to carry out an assessment of electricity security of supply risks; however, not all Member States describe the types of risks covered under the assessment[8]. The analysis shows that the risks to be assessed vary considerably[9]. Furthermore each Member State has designed its own "*risk preparedness*" or "*emergency plan*" to deal with stress situations, which has resulted in different national practices across Europe which tend to differ in nature, scope and content and rarely take into account cross-border effects. Diverging perception of risks could lead to different levels of preparedness.

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7 Only ten Member States set clear obligations to draw up risk preparedness plans, whilst eighteen other Member States do not have such an obligation, but take risk preparedness considerations into account in reports, plans or measures (source: Risk Preparedness Study).
In addition, Directive 2008/114/EC on the identification and designation of European critical infrastructures defines the obligation that each identified European Critical Infrastructure needs an operator security plan (Art. 5) which will be also reflected in the coming System Operation Guideline (Art. 26). However, these plans focus only on each identified asset and not the electricity system as whole.

8 Only nine Member States have direct obligations to carry out a risk assessment; other Member States are implicitly looking at risks when monitoring the security of electricity supply (source: *Risk Preparedness Study*).

9 23 Member States define risks to be addressed which vary considerably (source: *Risk Preparedness Study*).

The evidence shows that national plans **do not look at the impacts beyond the national borders or simultaneous crisis situations**. There is close cooperation on the level of TSOs which is not matched by a cooperation of national authorities[10].

Uncoordinated national measures to ensure the supply in emergency situations may not be efficient or could have negative effects on neighbouring countries. The lack of cooperation on the level of national authorities could also lead to diverging actions on TSO and governmental level (e.g. decision on governmental level on export bans) which could have detrimental effect on security of electricity supply.

Regarding transparency and information exchange, implementation of **Article 42** of the Electricity Directive shows that up to now the Commission was only notified of such measures in few cases (e.g. Poland in 2015[11]), and only ex-post, where there was no possibility ex-ante to assess their suitability. The current wording of Article 42 is of rather **general nature** and does **not lead to sufficient cross-border coordination beforehand**.

The Electricity Coordination Group has **limited powers** beyond the exchange of information. There is no explicit obligation to convoke the group in case of a crisis or when at least two Member States are in emergency. It is purely a consultative body without powers to issue recommendations for example on the measures that Member States could put in place during an emergency.

On **managing crisis situations**, currently Member States predominantly resort to national measures without sufficient account being taken of their impact on their neighbours or synergies stemming from a coordinated approach. There are hardly any cross-border procedures on how Member States should act in crisis situations. However, with increasingly integrated markets, measures taken by one Member State are highly probable to affect its neighbours. The cross-border impact is particularly serious and immediate in case of an actual physical shortage in real time[12].

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10 There are examples of existing regional co-operation is some regions involving national authorities, e.g. among the Nordic countries in the framework of NordBER (Nordic Contingency Planning and Crisis Management Forum) or Pentalateral Energy Forum, however, currently this co-operation is mainly restricted to the exchange of best practice.

11 Poland activated a crisis protocol mid-August 2015 allowing TSO to restrict power supplies to large industrial consumers (load restrictions did not apply however to households and some sensitive institutions such as hospitals). However, Poland notified the adoption of these measures under Article 42 one month after (mid-September).

12 Physical shortage arises when it has not been possible to fulfil the given demand, neither by market transactions in day-ahead and intraday markets nor by balancing activities of the TSO. In this case, load shedding will be carried out by each TSO to remedy its deficit. After market closure there is no ambiguity regarding the deficit’s allocation across affected countries – each TSO knows exactly the magnitude of its control area’s deficit and consequently its 'scheduled curtailment'. For exporting Member States who strive to protect their customers from disconnection, two scenarios may arise: (i) closing down interconnectors to stop exports altogether or (ii) carry out less-than-scheduled load shedding in order to reduce export flows. In both cases the national action can have an impact on cross-border power flows, affecting the neighbours' supply.

In case of a **simultaneous scarcity situation** in two or more Member States, stopping or limiting exports to overcome national physical shortage before domestic demand has been curtailed would directly translate into aggravating supplies to customers in the neighbouring Member State. The management of interconnectors and the possible spill over effects of Member States' national actions become particularly relevant when a concurrent physical energy shortage remains over several days (e.g. due to a heat wave/cold spell causing a sustained demand spike or when a large number of generation units is put out of operation). This case of energy shortage is especially exposed to the risk of intervention with system operation or premature non-market measures by Member States.

The network codes, i.e. the **draft NC ER, the CACM Guideline and the SO Guideline** are an important step in the harmonisation of technical procedures and interoperatibility of rules in the EU. However, a **general legislative framework** setting out how Member States should act and co-operate with each other to prevent and manage electricity crisis situations **is still missing**. There is still no framework clarifying roles and responsibilities, aligning national rules, and prescribing co-operation between Member States to resolve political issues relating to crisis management. As a result, large-scale electricity crisis situations, as well as situations of a simultaneous crisis, cannot effectively be resolved (for instance, there is no framework for how to deal with crisis situations caused by extreme weather conditions, or a fuel shortage; there are no rules on which consumers should be protected most, how to communicate and intervene at a political level etc).

Article 4(3) of the SoS Directive does not define clear Dos and Don'ts at the Member State level even though electricity crisis situations, especially in situations of simultaneous scarcity, which require political decision and clear rules, roles and responsibilities. In such situations, the market should be allowed to function as long as possible and deliver power flows to countries with higher scarcity. Exporting Member States should not introduce exports bans without restricting national consumers in a proportionate manner as this would 'export' the scarcity across the borders. The treatment of interconnection capacity and consequently the way possible load-shedding measures could be shared across countries is not sufficiently defined. A few Member States explicitly foresee (potentially unproportioned) export bans in their national legislation[13] and a recent case of export bans in South-Eastern Europe has proven this risk in reality.

On **cybersecurity**, the fragmented approach of the NIS directive could be problematic for the energy sector, as energy infrastructure is arguably one of the most critical infrastructures that other sectors - like banking, health and mobility, depend upon to deliver essential services. Currently, the energy sector consists of both legacy and next generation technologies. New grid technologies are introducing millions of novel, intelligent components to the energy sector that communicate in much more advanced ways (two-way communications, dynamic optimization, and wired and wireless communications) than in the past. These new components will operate in conjunction

[13] One Member State specifically includes a legal provision on export bans in its legislation; eleven more Member States include forms of export restrictions in national law, TSO regulations or multilateral agreements (Source: Risk Preparedness Study).

with legacy equipment that may be several decades old, and provide little to no cybersecurity controls. In addition, with alternative energy sources such as solar power and wind, there is increased interconnection across organizations and systems. With the increase in the use of digital devices and more advanced communications, the overall risk has increased. For example, as substations are modernized, the new equipment is digital, rather than analogue. These new devices include commercially available operating systems, protocols, and applications rather than proprietary solutions. This increased digital functionality provides a larger incident surface for any potential adversary, such as nation-states, terrorists, malicious contractors, and disgruntled employees. This new technology increases the complexity of addressing cyber risks. Many of the commercially available solutions have known vulnerabilities that could be exploited when the solutions are installed in control system components. Potential impacts from a cyber-event include: billing errors, brownouts/blackouts, personal injury or loss of life, operational strain during a disaster recovery situation, or physical damage to power equipment. The current legislative framework does not prepare for these impacts.

6.1.4. *Presentation of the options*

Options to reinforce coordination between Member States for preventing and managing crisis situations (Problem Area III)

Table 3: Overview of the Options for Problem Area III

Option 0:	Baseline scenario
Option 0+:	Improved implementation of current legislation without regulatory action at EU level
Option 1:	Common minimum rules to be implemented by Member States
Option 2:	Common minimum rules to be implemented by Member States plus regional cooperation
Option 3:	Full harmonisation and full decision-making at regional level

Option 0: Baseline scenario

Under the baseline scenario, Member States would continue **identifying and addressing rare/extreme risks and possible crisis situations based on a national approach**, in accordance with their own national rules and requirements. As a consequence, neither risks originating across borders, nor possible synergies in preparation for crisis are sufficiently taken into account.

The recently adopted network codes and guidelines (i.e. The Network Code on Emergency and Restoration, the Regulation on Capacity Calculation and Congestion Management and the Guideline on System Operation) bring a certain degree of harmonisation on how to deal with electricity systems in different states (normal state, alert state, emergency state, black-out and restoration). This ensures more clarity as regards how TSOs should act in crisis siuations, and as to how they should co-operate with one another.

The innovative tools[14] developed for TSOs in the area of the system security in the last years, will also contribute to improve monitoring, prediction and managing secure interconnected power systems preventing, in particular, cascading failures[15].

However, the TSOs cooperation would be limited to technical-level decisions, and would be hampered in practice by the absence of a proper framework for national rules and decisions on how to prepare for and handle electricity crisis situations, in particular in situations of siumultaneous scarcity. Such political decisions continue to be taken at a purely national level, in an intransparent manner, without taking account of other Member States' interests, both in a preparatory phase, and when crisis situations kick in.

Monitoring results would be published bi-annualy without any requirement to coordinate among each other or develop any risk preparedness plan. Furthermore Member States would not be obliged to **exchange information** when a possible crisis approaches. A current mandate of the **Electricity Coordination Group** would also not be sufficient to act as information exchange platform in crisis situations. This could lead to inefficiencies when preventing and managing a crisis situation or have negative effects on neighbouring countries.

On **cybersecurity**, the NIS Directive, aiming at a high common level of network and information security across the Union, provides the horizontal framework to boost the overall level of network and information security across the EU on a cross-sectoral and generic level. However, as the NIS Directive is defining only very generic and high-level obligations, there is room for a more sectoral approach defining concrete modalities to ensure a minimum of coordination among Member States and resilience of the interconnected European electricity grid. Energy infrastructure is arguably one of the most critical infrastructures that other sectors - like banking, health and mobility- which depend upon to deliver essential electricity services. Thus it is essential to tackle the potential risks of a major blackout taking into account coordinated attacks to more than one Member State and the interconnectivity and the system complexity of the energy sector.

[14] ITESLA project (which was financed under FP7) developed methods and tools for the coordinated operational planning of power transmission systems, to cope with increased uncertainties and variability of power flows, with fast fluctuations in the power system as a result of the increased share of resources connected through power electronics, and with increasing cross-border flows. The project shows that the reliance on risk-based approaches for corrective actions can avoid costly preventive measures such as re-dispatching or reduced the overall risk of failure.

[15] In addition the AFTER project (which was financed under FP7) also developed tools for TSOs to increase their capabilities in creating, monitoring and managing secure interconnected electrical power system infrastructures, being able to survive major failures and to efficiently restore service supply after major disruptions (http://www.after-project.eu/).

Table 4: R&D Results

The technical base to produce accurate prediction of rapid fluctuations and prevent cascading failures has been developed in **ITESLA** through a framework for the exchange dynamic models of power system elements. It showed that the reliance on risk-based approaches for corrective actions can avoid costly preventive measures such as re-dispatching or reduced while the overall risk of failure is decreased. This requires more and more formalised data exchange among TSO's to support the new methods and tools. **AFTER** has developed a framework for electrical power systems vulnerability identification, defence and restoration. It uses a large set of data (big data) coming from on-line monitoring systems available at TSOs' control centres. A fundamental outcome of the tool consists in risk-based ranking list of contingencies, which can help operators decide where to deploy possible control actions. **SESAME**, developed a comprehensive decision support system to help the main public actors in the power system, TSOs and Regulators, on their decision making in relation to network planning and investment, policies and legislation, to address and minimize the impacts (physical, security of supply, and economic) of power outages in the power system itself, and on all affected energy users, based on the identification, analysis and resolution of power system vulnerabilities.

Source: European Commission (DG ENER)

Table 5: Innovative Tools for Electrical System Security within Large Areas (ITESLA)

Project FP7-ITESLA

Innovative Tools for Electrical System Security within Large Areas

Addressing mainly: Co-optimisation of interconnection capacity, Regional operational centres

The project developed methods and tools for the coordinated operational planning of power transmission systems, to cope with increased uncertainties and variability of power flows, with fast fluctuations in the power system as a result of the increased share of resources connected through power electronics, and with increasing cross-border flows. The project aims at enhancing cross-border capacity and flexibility while ensuring a high level of operational security.

Fact Sheet: http://cordis.europa.eu/project/rcn/101320_en.html

Web Site: http://www.itesla-project.eu/

Important project outcomes include

- A platform of tools and methods to assist the cooperation of transmission system operators in dealing with operational planning from two days ahead to real time, particularly to ensure security of the system. These tools support the optimisation of security measures, in particular to consider corrective actions, which only need to be implemented in rare cases that a fault occurs, in addition to preventive actions which are implemented ahead of time to guarantee security in case of faults. The tools provide risk-based support for the coordination and optimisation of measures that transmission operators need to take to ensure system security. The platform also supports "defence and restoration plans" to deal with exceptional situation where the service is degraded, e.g. after storms, or to restore the service after a black-out. The platform has been made publicly available as open-source software.
- A clarification of the data and data exchanges that are necessary to enable the implementation of these coordination aspects.
- A framework to exchange dynamic models of power system elements including grids, generators and loads, and a library of such models covering a wide range of resources. These models are essential to produce accurate prediction of the rapid fluctuations that take place in the power grid after faults, and to prevent cascading failures.
- The tools and models allow reducing the amount of necessary preventive measures. The reliance on risk-based approaches can avoid or minimise costly preventive measures such as re-dispatching while the overall risk of failure is decreased.
- A set of recommendations to policymakers, regulators, transmission operators and their associations (jointly with the UMBRELLA project). These foster the harmonisation of legal, regulatory and

operational framework to allow the exploitation of the newly developed methods and tools. They also identify the need for increased formalised data exchange among TSO's to support the new methods and tools.

Source: European Commission (DG ENER)

Option 0+: Non-regulatory approach

As current legislative framework established by the SoS Directive set general principles rather than requires Member States to take concrete measures, better implementation and enforcement actions will be of no avail.

In fact, as the progress report of 2010 shows[16], the SoS Directive has been implemented across Europe, but such implementation did not result in better co-ordinated or clearer national policies regarding risk preparedness.

The recently adopted network codes and guidelines offer some improvements at the technical level, but do not address the main problems identified.

In addition, today voluntary cooperation in prevention and crisis management is scarce across Europe and where it takes place at all, it is often limited to cooperation at the level of TSOs. It is true that certain Member States collaborate on a voluntary basis in order to addresss certain of the problems identified (e.g. Nord-BER, PLEF). However, these initiatives have different levels of ambition and effectiveness, and they geografically cover only part of the EU electricity market. Therefore, voluntary cooperation will not be an effective tool to solve the problems identified timely and in the whole EU.

Option 1: Common minimum rules to be implemented by Member States

Assessments and plans

Under Option 1 Member States would be obliged to develop **national** Risk Preparedness Plans ('Plan') with the aim to prevent or better manage the electricity crisis. The Plan should respect minimum common requirements and include a **risk assessment** of the most relevant crisis scenarios originated by rare/extreme risks. For that purpose, at least the following types of risks could be considered: a) rare/extreme natural hazards[17], b)

[16] *Report on the progress concerning measures to safeguard security of electricity supply and infrastructure investment* COM (2010) 330 final.

[17] Extreme weather events are likely to affect the power supply in various ways: (i) thermal generation is threatened by lack of cooling water (as shown e.g. in summer 2015 at the French nuclear power stations Bugey, St. Alban and Golfech); (ii) heat waves cause high demand of air conditioning (which e.g. resulted in price peaks in Spain in late July 2015 when occurring in parallel with low wind output); (iii) heat waves affect grid performance in various ways, e.g. moisture accumulating in transformers (which e.g. lead to blackouts in France on June 30th 2015) or line overheating (leading to declaration of emergency state by the Czech grid operator CEPS on July 25th in 2006) (source: S&P Global, Platts: *European Power Daily*, Vol. 18, Issue 123).

accidental hazards which go beyond N-1, c) consequential hazards such as fuel shortage[18], d) malicious attacks (terrorist attacks, cyberattacks).

The Plans would need to respect a set of minimum requirements, namely how Member States **would prepare for crisis situations** and how they should **deal with the identified crisis** scenarios. Preparatory measures could include, e.g. training for all staff involved in crisis management and regular simulations of crisis. Risk preparedness plans should further include how to prevent and manage cyber-attack situations which would be one of the risks to be covered by the plans. This will be combined with a soft guidance on cybersecurity in the energy sector based on NIS Directive.

Plans should be adopted by relevant governments / ministries, following an inclusive process, and (at least some parts of the Plans) should be rendered public. Plans should be **updated on a regular basis** (e.g., every three years, unless major incidents or market developments require an earlier update). For the purpose of consultation, Plans should be submitted to other Member States and the Commission.

The main benefit this option would bring is better preparedness, due to the fact that a common approach is followed across Europe, thus excluding the risk that some Member States 'under-prepare'. In addition, better preparedness, transparency and clear rules on crisis management are likely to reduce the chances of premature market intervention.

Crisis management

To ensure transparency and information exchange, Member States would be obliged to inform **immediately in situations of "*early warning*" or "*crisis*"** their neighbours and the European Commission to provide them with all the necessary information, in particular on the actions they intend to take.

"*Early warning*" could be defined as the state where there is concrete, serious and reliable information that an event may occur which is likely to result in significant deterioration of the supply situation and is likely to lead to a crisis level. While "*crisis*" could be defined as the event of significant deterioration of electricity supply over a time span lasting long enough to give room for political action and when all relevant market measures have been implemented but the supply is insufficient to meet the remaining demand[19].

[18] One example proving that such risks should be taken into account is the shortage of anthracite coal in Ukraine in June 2016. Due to the political situation in Ukraine affected the rail transport of coal. As several Ukrainian nuclear power units are offline for maintenance in parallel, the responsible ministry called for limiting power consumption. (Source: S&P Global, Platts: *European Power Daily*, Vol. 18, Issue 123).

[19] In most of the cases the declaration of "*crisis*" by the national authorities will coincide with the "*emergency state*" of the transmission system as severe technical problems could lead to the "*exceptional situation*". But in very extreme or rare cases where situations demand political decisions and are not solely limited to system operation in real time (e.g. fuel supply scarcity, energy shortage for longer time periods) the government could decide to declare emergency - without necessary being in "*emergency state*"- with the aim to take safeguard measures (non-market based measures).

Under this option, the Commission could also set out legal principles governing **crisis management**. This will replace the current Article 42 of the Electricity Directive, which allows Member States to take 'safeguard measures' in situations of a sudden crisis and when security of persons or equipment is threatened. When dealing with emergency Member States should respect three basic rules:

- *'Market comes first'*: Non-market measures should be introduced only once market measures cannot tackle the situation. Measures should not unduly distort functioning of the market. They should be introduced only temporary and on the basis of an objective trigger described in the Plans. In particular, market rules on cross-border trade need to be respected[20].

- *'Duty to offer assistance':* In case crisis arises, Member States should react in a spirit of good cooperation and solidarity[21]. Practical arrangements regarding cooperation and solidarity measures shall be established in advance by Member States and be reflected in the risk preparedness plans.

- *'Transparency and information exchange'*: Member States should ensure transparency of the actions taken from the moment that there are serious indications of a crisis and during a crisis. This should be ensured through the regional part of the risk preparedness plans and through informing neighbours and the Commission in case of declaration of 'early warning' or 'crisis'.

By imposing obligations to co-operate and lend assistance, Member States are also less likely to 'over-protect' themselves against possible crisis situations, which in turn will contribute to more security of supply at a lesser cost.

Monitoring

In order to anticipate and mitigate potential upcoming crisis, under Option 1 Member States would be obliged to take into account the **results of the ENTSO-E seasonal assessments** (winter & summer outlooks). Member States should take measures accordingly, if there are serious indications that they could be in a predefined crisis situation (i.e. in an 'early warning' situation), as well as in a situation of crisis.

Option 2: Common minimum rules to be implemented by Member States plus regional co-operation

Assessments and plans

Option 2 would be built on Option 1 adding rules and tools facilitating cross-border cooperation in a regional and Union wide context.

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20 Rules on cross-border capacity allocation are set out in the CACM Guideline. Its Article 72 allows TSOs to curtail allocated cross-zonal capacity in the event of 'force majeure'.

21 At TSO level, providing cross-border assistance through the available interconnectors is provided for in Article 12 of the draft Network Code on Emergency and Restoration.

Under Option 2 Member States should also develop their Risk Preparedness Plans. However, the identification of the **crisis scenarios and the risk assessment** would be carried out by ENTSO-E. This approach would ensure that the risks originating across the borders, including scenarios of a possible simultaneous crisis, are taken into account. ENTSO-E would be required to develop a methodology for the identification of risk scenarios. Such methodology would need to include at least following elements:

- consider all relevant national and regional circumstances;
- the interaction and correlation of risks across the borders;
- running simulations of simultaneous crisis scenarios;
- ranking of risks according to their impact and probability.

To take account of all regional specificities ENTSO-E could delegate all or part of its tasks to the ROCs. The crisis scenarios identified by ENTSO-E would be discussed in the Electricity Coordination Group. The regional approach in the **identification of the crisis scenarios** ensures a common strategy to minimise impacts of possible crisis, focus in particular on correlated risks and on risks that could affect simultaneously several Member States. This would significantly improve level of preparedness at national, regional and EU level, as the cross-border considerations are duly taken into account since the beginning.

Table 6: Best practice examples of Member State cooperation

Nordic Contingency and Crisis Management Forum (NordBER) The Nordic (including Iceland) TSOs, regulators and energy authorities founded a Nordic cooperation body (NordBER) in order to improve crises management and preparedness. The cooperation focuses on the exchange of information and experiences on contingency planning and emergency exercises. Moreover, it requires a common contingency planning for the overall Nordic power sector as a supplement to the national emergency work and as an extension of operation and planning cooperation between the TSOs. *Pentalateral Energy Forum* The Pentalateral Energy Forum is the framework for regional cooperation of relevant ministries, NRAs, TSOs and market parties in Central-Western Europe (BENELUX-DE-FR-AT-CH). Its Support Group 2 gives guidance on regional cooperation in the field of security of supply and acts as "development center for new ideas" with the goal to reach specific recommendations.

Source: https://nordber.org/ and http://www.benelux.int/nl/kernthemas/energie/pentalateral-energy-forum/

The **Risk Preparedness Plans** under this option **would contain two parts** – a part reflecting national measures and a part reflecting measures to be pre-agreed in a regional context. The latter part includes particular preparatory measures such as simulations of simultaneous crisis situations in neighbouring Member States ("stress tests" organised by ENTSO-E in a regional context); procedures for cooperation with other Member States in different crisis scenarios, and rules for how to deal with simultanous crisis situations. In this context the Member States should, among others, agree in advance in which situations, what load and to whom will be curtailed in simultaneous crisis situations. In order to facilitate the extent of offered assistance, in particular in cases where no other agreement has been made for assistance in simultaneous crisis, it might be necessary to allign principles for priorization and the share of customers which is prioritized highly in order to avoid overprotection at the cost of neighbouring Member States.

The draft Plans should be consulted with other Member States in each region and submitted for prior consultation to the Electricity Coordination Group. Through regionally co-ordinated plans, Member States would be able to ensure that increased TSO cooperation is matched by a more structured co-operation between Member States[22]. The regions for such cooperation should therefore be the same as the TSO regions developed for the RSCs. To ensure cooperation further, the obligation on coordinated planning should be extended to Energy Community Partners.

To facilitate the cross-border cooperation and to overcome the current situation of unclear roles and responsibilities, Member States should designate one **'competent authority'**, which would be the responsible body for coordination and cross-border cooperation in a crisis situation. The Competent Authority should belong either to the national administration or to the NRA.

In order to also adress specific rules to be followed to ensure **cybersecurity** a network code or guideline should be developed.The network code/guidelines should take into account at least the following elements: a) methodology to identify operators of essential services for the energy sector; b) risk classification scheme; c) minimum cyber-security prerequisites to ensure that the identified operators of essential services for the energy sector follow minimum rules to protect and respond to impacts on operational network security taking the identified risks into account. A harmonized procedure for incident reporting for the energy sector shall be part of the minimum prerequisites.

Crisis management

As described in Option 1, all measures taken by Member States to prepare to or deal with 'crisis' should be based on a **common framework** and the principles of 'market comes first', 'duty to offer assistance' and 'transparency and information exchange'.

The 'duty to offer assistance' should especially address simultaneous scarcity situations which would be set to further rise in the near future given the increasing interconnectivity of the European electricity systems and markets (see Graphs 1 and 2). In situations of concurrent energy shortage over several days[23], Member States should agree in advance, when and what loads would be curtailed in crisis situations with a cross-border impact[24]. Solidarity measures in simultaneous scarcity, including coordinated demand restrictions

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[22] For cases of crisis, in particular simultaneous scarcity, also ENTSO-E sees a need for "*not only on a technical level but political cooperation*" and plans which "should cover extreme crisis situations beyond the measures provided by e.g. network codes and RSCs services" (s. *ENTSO-E recommendations to the regulatory framework on risk preparedness (WS5)* (2016), ENTSO-E, document in the process of publication).

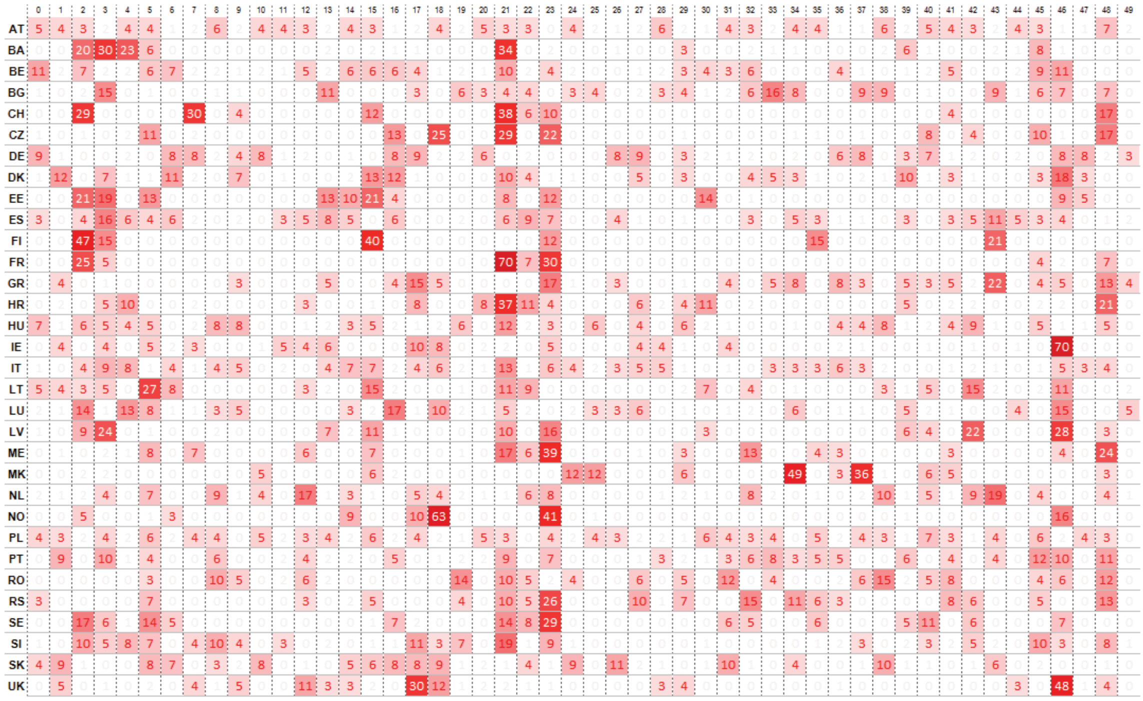
[23] Unlike sudden power outages, an energy shortage could be (i) anticipated e.g. several days in advance and (ii) last over a period of several days. Therefore, decision making on customer disconnection, rota plans etc. is likely to not only affect TSOs, but also involve Member States. A good example of a rota plan is the "*Electricity Supply Emergency Code*" of the UK: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/396424/revised_esec_january_2015.pdf

[24] One example of a load shedding plan prioritizing regions is the Belgian "*Plan de délestage en cas de pénurie d'électricité*" http://economie.fgov.be/fr/penurie_electricite/plan-delestage/#.VpTd2v7luUk

in various markets, could be subject to financial compensation ex-post, following agreements between Member States according to the principles set out in Article 39 of NC ER (avoiding market distortion, incentivizing balanced positions). In order to avoid 'exporting' energy scarcity to neighbouring markets Member States should also allow for domestic load shedding to be carried out by their TSOs according to schedules. Any rules on protected customers should not lead to unjustified over-protection of a too high share of national customers[25].

[25] As already existing in many Member States today, Member States can introduce rules on customer categorization to prioritize customers in case of load shedding. Such rules on protected customers should take into account national and local specifics, but respect harmonized principles.

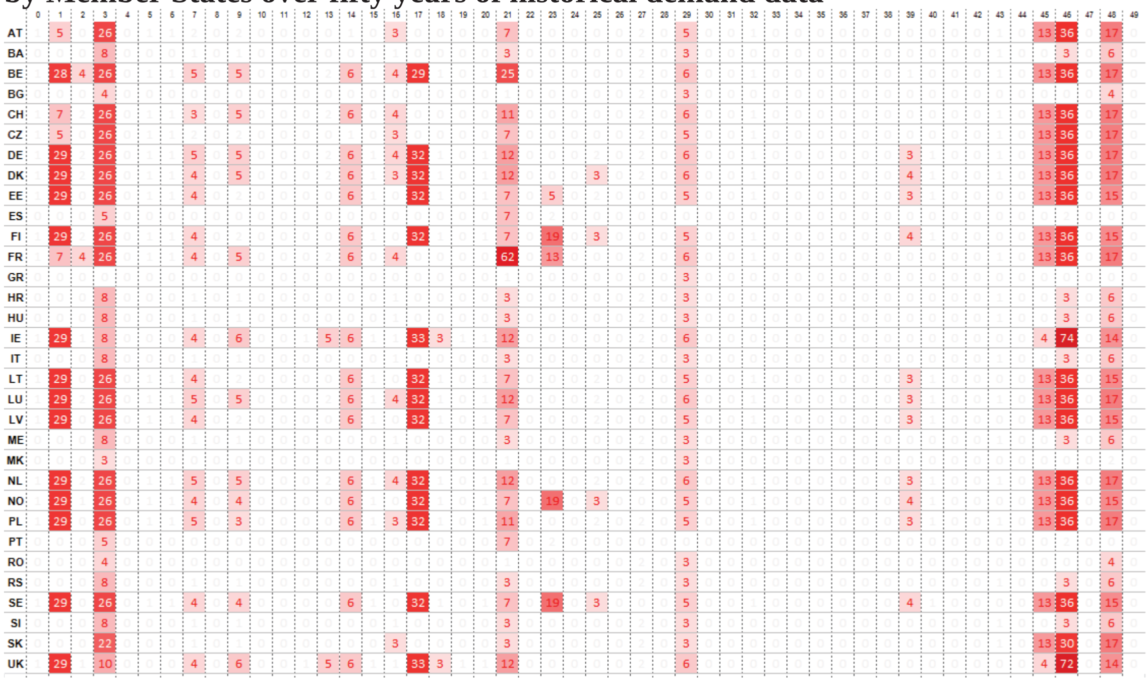
Graph 1: Distribution of system stress hours by Member States over fifty years of historical demand data



Stress hours are defined as hours of extremely high demand. The graph shows the 150 hours per Member State of the highest demand in the historical period of fifty years (1960-2010). The intensity of the colour indicates the intensity of demand (red means super peaks of demand). Rows indicate Member States. Columns indicate the respective historical years.

Source: METIS

Graph 2: Distribution of prices at VoLL in the context of a well-integrated market by Member States over fifty years of historical demand data



As result of better integration of the markets the stress hours would decrease and be concentrated in periods affecting simultaneously several Member States.

During these stress hours the price becomes equal to VoLL.

Source: METIS

Table 7: Best practice example of TSO agreements of Nordel

The Nordic TSOs pre-agreed on certain procedures to be taken in crisis situations (s. Apendix 9 of Nordel System Operation Agreement 3 (5)). In *Power Shortages*, it demands information of the other TSOs as quickly as possible and forbids that prearranged trading between players can be changed. In *Critical Power Shortages* and after all manual balancing reserve (i.e. available generation capacity) has been exhausted, it sets out a procedure for load shedding without a commercial agreement. After the subsystem with the greatest physical deficit has started load shedding and two or more subsistems have an equally large deficit, load shedding is distributed thereafter between those subsystems[26].

Source: Nordel System Operation Agreement 1 (5), Appendix 9

Monitoring

Building on Option 1, ENTSO-E would carry out seasonal assessments, which would need to be further improved via the introduction of a **common methodology**, to be developed by ENTSO-E on the basis of criteria set out in EU legislation. This could be a probabilistic methodology that should take into account uncertainties of input variables (e.g. probability of transmission capacity outage, of severe weather conditions, of unplanned outage of power plants, variability of demand, etc.). The methodology would also indicate the probability of a critical situation actually occuring and of low level of cross-border capacity. This methodology should be used not only for seasonal outlooks but also for weekly risk assessments by RSCs.

This option also contemplates the **reinforcement of tasks and powers of the Electricity Coordination Group** with a view to ensure transparency and wide discussion between Member States in the preventive phase and after declaration of early warning/crisis. In particular, the Group would be the forum for the discussion of the draft plans and the measures that Members States foresee to implement based on the results of the seasonal outlooks. The Group could also play a role in the assessment of measures adopted by Member States in early warning/crisis. More generally, the Group could be given concrete tasks to discuss policies in the area of security of supply, for instance, through regular discussions on the basis of ENTSO-E adequacy outlooks. It could issue recommendations and develop best practice. The reinforced role would enhance the coordination of measures and ensure more uniformity and coherent plans. Overall, the reinforcement of tasks and powers of the Electricity Coordination Group would contribute to enhance cooperation and to build trust and confidence among Member States.

In addition to the obligation to notify immediately the declaration of early warning or crisis and provide Member States concerned and the Commisison with all relevant information, under Option 2 Member States would be obligated to carry out **an ex-post evaluation**. The evaluation should be submitted to the Commission at the latest six weeks after the lifting of early warning or crisis. The assessments should be presented by the Member States concerned at the Electricity Coordination Group.

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[26] That agreements similar to the Nordic TSOs could be a best practice also for the system of continental Europe as it mentioned by the Dutch TSO TenneT to the public consultation. It recommends to have common rules and definitions and defining allowed measures on different levels of criticality, as security of electricity supply is becoming an issue of reginal rather than national importance.

To allow for a precise monitoring of how well Member States' systems perform in the area of security of supply, **security of supply indicators** would be introduced. ENTSO-E would calculate for all Member States the following security of supply indicators: expected energy non served (EENS) expressed in GWh/year and loss of load expectation (LOLE) expressed in hours/year. ENTSO-E would conduct the security of supply performance measurements based on the indicators on annual basis, at the occasion of the adequacy assessment outlook. The introduction of security of supply indicators to assess how well Member States perform in the area of security of supply would enhance comparability and mutual trust in neighbours.

Option 3: Full harmonisation and full decision-making at regional level

Assessments and plans

Built on Option 2, under Option 3 the assessment of rare and extreme risks would be carried out at EU level, which would prevail over national assessments.

The **risk preparedness plans** would be developed on **regional level**[27]. In each region the Member States would need to agree on one risk preparedness plan which would address the most relevant risks in each region. The list of measures to mitigate the risks should be developed on and co-ordinated at the regional level by the ROCs. This would allow a harmonised response to potential crisis situation in each region.

Even though the regional plans would ensure full coherence of actions ahead and in particular in a crisis, it would be difficult that all national specificities could be addressed through regional plans.

On **cybersecurity** Option 3 would go one step further and nominate a dedicated body (agency) to deal with cybersecurity in the energy sector. This would guarantee full harmonisation on risk preparedness, communication, coordination and a coordinated cross-border reaction on cyber-incidents.

Crisis management

Regarding **crisis management**, under Option 3 crisis would have to be managed according to the regional plans agreed among Member States. The Commission would determine the key elements of the regional plans such as: commonly agreed regional load-shedding plans, rules on customer categorisation, a harmonised definition of 'protected customers' (high priority grid users) at regional level or specific rules on crisis information exchanges in the region. Under Option 3, the Commission would also create a **detailed 'emergency rulebook'** with an exhaustive list of measures that can be taken by Member States and TSOs in crisis situations.

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[27] The results of the public consultation showed that only few stakeholders were in favour of regional or EU wide plans. Some stakeholders mentioned the possibility to have plans on all three levels (national, regional and EU), e.g. see the answers of Latvian government, EDSO, GEODE, Europex.

Monitoring

The seasonal outlooks carried out by the ENTSO-E and ROCs would include a proposal of ROCs for each reagion of measures to mitigate the risks identified. Member States would be obligated to implement them.

In order to also harmonize monitoring practices on a European level and ensure full consistency, a European standard (e.g. for EENS and LOLE) on Security of Supply could be developed and fixed (e.g. determined value to be fulfilled by all Member States) which could be used to monitor the Member State performance.

6.1.5. *Comparison of the options*

Option 1 (Common minimum rules to be implemented by Member States)

Contribution to the policy objectives

Under this option, Member States would be required to draw up risk preparedness plans, built on common elements, and to respect certain common minimum rules when managing crisis situations.

The main benefit this option would bring is better preparedness, due to the fact that a common approach is followed across Europe, thus excluding the risk that some Member States 'under-prepare'. In addition, better preparedness, transparency and clear rules on crisis management are likely to reduce the chances of premature market intervention.

By imposing obligations to co-operate and lend assistance, Member States are also less likely to 'over-protect' themselves against possible crisis situations, which in turn will contribute to more security of supply at a lesser cost.

Economic Impacts

Overall, the policy tools proposed under this option should have positive effects. Putting in place a more common approach to crisis prevention and management would not entail additional costs for businesses and consumers. It would, by contrast, bring clear benefits to them.

First, a more common approach would help better prevent blackout situations, which are extremely costly. The immense costs of large-scale blackouts provide an indication of potential benefits of improved preparation and prevention[28].

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[28] Previous blackouts in Europe had severe consequences. For example, the blackout in Italy in September 2003 resulted in a power disruption for several hours affecting about 55 million people in Italy and neighbouring countries and causing around 1.2 billion euros worth of damage. (source: *The costs of blackouts in Europe* (2016), EC CORDIS: http://cordis.europa.eu/news/rcn/132674_en.html).

Table 8: Overview over most severe blackouts in Europe

Country & year	Number of end-consumers interrupted	Duration, energy not served	Estimated costs to whole society
Sweden/Denmark, 2003	0.86 million (Sweden); 2.4 million (Denmark)	2.1 hours, 18 GWh	EUR 145 – 180 million
France, 1999	1.4 - 3.5 million	2 days–2 weeks, 400 GWh	EUR 11.5 billion
Italy/Switzerland, 2003	55 million	18 hours	
Sweden, 2005	0.7 million	1 day – 5 weeks, 11 GWh	EUR 400 million
Central Europe, 2006	45 million	Less than 2 hours	

Source: SESAME: Securing the European Electricity Supply Against Malicious and Accidental Threats

A more common approach to emergency handling, with an obligation for Member States to help each other, would help to avoid or limit the effects of potential blackouts. A more common approach, with clear obligations to e.g., follow up on the results of seasonal outlooks, would also reduce the costs of remedial actions TSOs have to face today[29]. This, in turn, should have a positive effect on costs overall.

In addition, improving transparency and information exchange would facilitate coordination, leading to a more efficient and less costly measures.

By ensuring that electricity markets operate as long as possible also in stress situations, cost-efficient measures to prevent and resolve crisis are prioritized.

The overall impact of the Commission Recommendations on cybersecurity for the energy sector can be very broad, given the voluntary nature of this approach. If fully followed by all Member States, the same impacts as in Option 2 should be considered. If only partially considered by Member States, the average administrative cost would be rather low.

Who should be affected and how

Option 1 is expected to have a positive effect on society at large and electricity consumers in particular, since it helps prevent crisis situations and avoid unnecessary cut-offs. Given the nature of the measures proposed, no major other impact on market participants and consumers is expected.

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29 The example of the Summer Outlook 2016 for Poland involves the following remedial actions to prevent emergency situations: (i) switching measures of the respective TSOs PSE and 50Hertz, as well as (ii) rescheduling of DC loop flows involving DE, DK, SE, PL, (iii) bilateral re-dispatch between DE and PL and (iv) multilateral re-dispatch additionally involving e.g. AT, CH. Out of those, (i) and (ii) are non-costly measures whereas re-dispatch induces significant costs.

On cybersecurity, given the voluntary approach of this option, several stakeholders (TSOs, DSOs, generators, suppliers and aggregators) could be affected. However, the impact is estimated limited as the costs of cybersecurity for regulated entities merely need to get considered and taken into account by the regulatory authority. Thus, the TSOs and DSOs affected could recover their costs via grid tariffs. In that case, the pass through of costs would have an impact on consumers that could see a slightly increased in the final prices of electricity.

Impact on business and public administration

The preparation of risk preparedness plans as well as the increased transparency and information exchange in crisis management imply a certain administrative effort[30]. However, the impact in terms of administrative impact would remain low, as currently Member States already assess risks relating to security of supply, and all have plans in place for dealing with electricity crisis situations[31].

In addition, it is foreseen to withdraw the current legal obligation for Member States to draw up reports monitoring security of supply[32], as such reporting obligation will no longer be necessary where national plans reflect a common approach and are made transparent. This would reduce administrative impacts.

Option 2 (Common minimum rules to be implemented by Member States plus regional co-operation)

Contribution to the policy objectives

Option 2 build on Option 1, but adds the dimension of regional (and some) EU-level co-operation. In particular, it requires Member States to pre-agree on certain aspects of the Risk Preparedness Plans (notably on how to deal with situations of a simultaneous electricity crisis). It also calls for a more systematic assessment of rare/ extreme risks at the regional level. Given the interlinked nature of EU's electricity systems, enhanced regional co-operation brings clear benefits when it comes to preventing and managing crisis situations.

The regional approach in the identification of the crisis scenarios ensures a common strategy to minimise impacts of possible crisis, focus in particular on correlated risks and on risks that could affect simultaneously several Member States. This would significantly improve level of preparedness at national, regional and EU level, as the cross-border considerations are duly taken into account since the beginning. The regional coordination of plans would build trust between Member States which is crucial in times of crisis. The

[30] Administrative costs are defined as the costs incurred by enterprises, the voluntary sector, public authorities and citizens in meeting legal obligations to provide information on their action or production, either to public authorities or to private parties.

[31] All twenty-eight Member States have a general obligation to monitor the security of electricity supply from which implicitly follows the obligation to assess electricity supply risks, while nine countries have a direct legal obligation to carry out an assessment of these risks. (Source: *Risk Preparedness Study*).

[32] Article 4 of the Electricity Directive; Article 7 of the Electricity SoS Directive.

harmonised approach via Network Codes/Guidelines would also ensure a minimum level of harmonization for cybersecurity in the energy sector throughout the EU.

The agreement at **regional level of some aspects of the risk preparedness plan** would ensure that coordination and cooperation is agreed in advance. This is particularly relevant as regards situations of simultaneous crisis.

The regional approach for the **ENTSO-E's seasonal outlooks** would ensure a more granular and in-depth assessment of possible cross-border situations. This could give a better indication of the impacts of possible crisis situations and the possible solutions that cooperation could bring.

The introduction of **security of supply indicators** to assess how well Member States perform in the area of security of supply would enhance comparability and mutual trust in neighbours.

The reinforced role of the **Electricity Coordination Group** would ensure transparency and wide discussion in prevention and managing crisis. It would also facilitate the exchange of information in situations of early warning and crisis and the ex-post evaluation. In addition, it would enhance the coordination of measures and ensure more uniformity and coherent plans. Overall, the reinforcement of tasks and powers of ECG would contribute to enhance cooperation and to build trust and confidence among Member States.

Economic Impacts

This option would lead to better preparedness for crisis situations at a lesser cost through enhanced regional coordination. The results of METIS simulations[33] show that well integrated markets and regional coordination during periods of extreme weather conditions (i.e. very low temperature[34]) are crucial in addressing the hours of system stress hours (i.e. hours of extreme electricity demand), and minimizing the probability of loss of load (interruption of electricity supply).

Most importantly, while a national level approach to security of supply disregards the contribution of neighboring countries in resolving a crisis situation, a regional approach to security of supply results in a better utilization of power plants and more likely avoidance of loss of load. This is due to the combined effect of the following three factors: (i) the variability of renewable production is partly smoothed out when one considers large geographical scales, (ii) the demands of different countries tend to peak at different times, and (iii) the power supply mix of different countries can be quite different, leading to synergies in their utilization.

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33 "*METIS Study S16: Weather-driven revenue uncertainty for power producers and ways to mitigate it"*, Artelys (2016).

34 Even though periods with very low temperature occur rarely (9C difference between the 50 year worst case and the 1% centile) countries can face high demand peaks (e.g. Nordic countries and France) mainly due to the high consumption for the electric heating. As example, the additional demand for the 50 years peak compared to the annual peak demand is 23% for France, 18% for Sweden and 17.3% for Finland.

The following table compares the security of supply indicator "expected energy non-served" (EENS) assessed by METIS for the three levels of coordination (national, regional, European)[35]. It highlights an overestimation of the loss of load, when it is measured in a scenario of non-coordinated approach, which does not take into account the potential mutual assistance between countries.

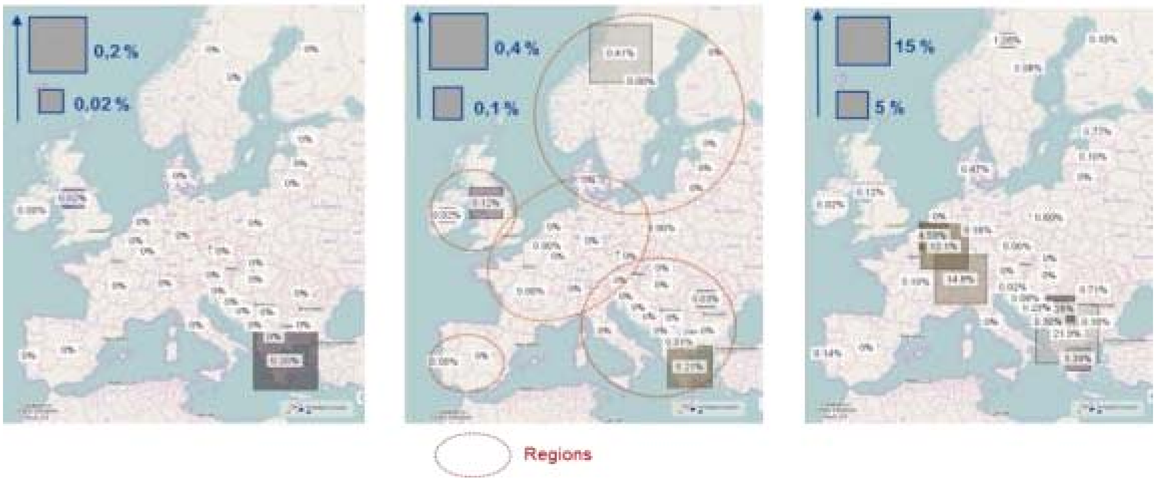
Table 9 - Global expected energy non-served as part of global demand within the three approaches

Level	EENS (% of annual load) – ENTSO-E V1[36] scenario
National level	0,36 %
Regional level	0,02 %
European level	0,01 %

Source: METIS

The EENS for the three levels of coordination are represented on the figure below. When the security of supply is assessed at the national level, many countries of central Europe seem to present substantial levels of loss of load. However, since these countries are interconnected, a regional assessment of security of supply (taking into account power exchanges within this region) significantly decreases the loss of load levels.

Figure 1 - EENS (%) estimation by country for scenario ENTSO-E 2030 v1 with CCGT/OCGT current generation capacities. From left to right: EENS estimated at European, regional and national levels



Source: METIS

[35] "*METIS Study S04: Stakes of a common approach for generation and system adequacy*", Artelys (2016).

[36] *ENTSO-E 2030 v1: vision for 2030 "Slowest progress". The perspective of Vision 1 is a scenario where no common European decision regarding how to reach the CO2-emission reductions has been reached. Each country has its own policy and methodology for CO2, RES and system adequacy.*

METIS simulations also show that thanks to regional cooperation the stress situations would decrease and concentrate in a limited number of hours that may occur simultaneously. Therefore, it highlights the need for specific rules on how Member States should proceed in these particular circumstances, as proposed in this Option 2.

As the overall cost of the system would decrease thanks to enhanced coordination this could have a positive impact on prices for consumers.

On the contrary, a lack of coordination on how to prevent and manage crisis situations would imply significant opportunity costs. A recent study also evidenced that the integration of the European electricity market could deliver significant benefits of 12.5 to 40 billion euro until 2030. However, this amount would be reduced by 3 to 7.5 billion euro when Member States pursue security of electricity supply objectives following going alone approaches[37].

Overall, the costs to develop and to follow a Network Code or Guidelines on cyber-security would be limited. Additionally, given the administrative nature of the Option, the impact could be estimated limited as it mostly requires harmonising existing practices available in most of Member States. In addition, some obligations specific for the energy sector would reinforce existing provisions on the NIS Directive such as the identification of operations of essential services and the reporting obligation of cyber-incidents. Security does in general not present a separate budget line; that is why it is very hard to estimate how much is already spent on cybersecurity expenditures. Some of the costs might also be hidden in other budget lines, like in human resources, securing buildings, etc. Thus there is very few evidence on cybersecurity expenses in the energy sector. As example, according to a US survey in a small sample of 21 utilities and energy companies, they spent an average of $45.8 million a year on computer security to prevent 69% of known cyber strikes against their systems in 2011[38.] On the contrary, the damages of cybersecurity breaches could be huge. Even though the range of costs varies on the incident, a recent study reveals a wide spectrum of costs ranging from $156,000 (very low end estimate) to $5.5 million per single event[39]. Additional costs may arise through losses in stock value. Overall, the costs of a blackout following a cyber-incident are the same as for a physical incident. Therefore, the overall impact of rules on cybersecurity would be limited while the benefits of preventing cyber-incidents could be high.

Who should be affected and how

As in the case for Option 1, Option 2 is expected to have a positive effect on society at large and electricity consumers in particular, since it helps prevent crisis situations and

37 *"Benefits of an Integrated European Energy Market (2013)"*, BOOZ&CO.

38 *Insurance as a risk management instrument for energy infrastructure security and resilience* (2013), U.S. Department of Energy: http://www.bloomberg.com/news/articles/2012-02-01/cyber-attack-on-u-s-power-grid-seen-leaving-millions-in-dark-for-months.

39 *Insurance as a risk management instrument for energy infrastructure security and resilience"* (2013), U.S. Department of Energy: http://www.bloomberg.com/news/articles/2012-02-01/cyber-attack-on-u-s-power-grid-seen-leaving-millions-in-dark-for-months.

avoid unnecessary cut-offs. Given that, under Option 2, Member States would be required to effectively cooperate, and tools would be in place to monitor security of supply via the Electricity Coordination Group, such crisis prevention and management would be even more effective.

The measures would also have a positive effect on the business community, as there would be much more transparency and comparability as regards how Member States prepare for and intend to manage crisis situations. This will increase legal certainty for investors, power generators, power exchanges but also for TSOs when managing short-term crisis situations.

Among the stakeholders the most affected would be the competent authorities (e.g. Ministry, NRA) as actors responsible for the preparation of the risk preparedness plans (see below, assessment of impacts on public authorities).

Other actors, such as TSOs, could be also affected, given in particular the possibility for the Competent Authorities to delegate certain tasks (e.g. carry out the risk assessment). However, as the tasks delegated would be closely linked to the tasks attributed by law to the TSOs (e.g. ensuring the ability of the system to meet demand), the impact of the specific tasks delegated would be limited.

ENTSO-E could be affected as well as it has to identify the cross-border scenarios and improved the seasonal outlooks with more robust regional analysis. Given the possibility for ENTSO-E to delegate certain tasks to the ROCs, the national TSOs as members of the ROCs could be also affected. However, the impact would remain limited given the current experience of TSOs on risk analysis and the existing cooperation among the TSOs.

Impact on business and public authorities

The assessment of this option shows a limited increase in administrative impact, although it would be to some extent higher than Option 1, given that national authorities would be required to pre-agree part of their risk preparedness plans in a regional context.

However, existing experiences show that a more regional approach to risk assessment and risk preparedness is technically and legally feasible. Further, since the regional parts of the plans would in practice be prepared by regional co-ordination centres between TSOs, the overall impact on Member States' administrations in terms of 'extra burdens' would be limited, and be clearly offset by the advantages such co-operation would bring in practice.[40]

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[40] The Nordic TSOs, regulators and energy authorities cooperate through *NordBER*, the Nordic Contingency and Crisis Management Forum. This includes information exchange and joint working groups and contingency planning for the overall Nordic power sector as a supplement to the national emergency work and TSO cooperation (www.nordber.org).

In addition, more regional cooperation would also allow Member States to create synergies, to learn from each other, and jointly develop best practices. This should, overtime, lead to a reduction in administrative impacts.

Finally, European actors such as the Commission and ENTSO-E would provide guidance and facilitate the process of risk preparation and management. This would also help reduce impacts on Member States.

It should be noted, that under Option 2 (as is the case for Option 1) no new body or new reporting obligation is being created, and that existing obligations are being streamlined. Thus, the Electricity Coordination Group is an existing body meeting regularly, for the future it is foreseen to make this group more effective by giving it concrete tasks. Further, national reporting obligations would be reduced (e.g. repealing the obligation of Article 4 of Electricity Directive) and EU-level reporting would take place within the context of existing reports and existing reporting obligations (e.g. ACER annual report Monitoring the Internal Electricity and Natural Gas Markets).

Option 3 (Full harmonisation and full decision-making at regional level)

Contribution to the policy objectives

The measures of this Option pursue the maximum level of harmonisation at EU level with the clear aim to increase the level of preparedness ahead of a crisis and the mitigation of the impact in the case of an unexpected event occurs.

The starting point for this option is the preparation of **risk preparedness plans at regional level**. Even though the regional plans would ensure full coherence of actions ahead and in particular in a crisis, it would be difficult that all national specificities could be addressed through regional plans.

The creation of a new EU agency dedicated to cybersecurity in the energy sector would ensure full harmonisation on risk preparedness, communication and coordination across Europe. Additionally, the agency would facility a quick and coordinated cross-border reaction on cyber-incidents.

Economic Impacts

The regional coordination through the regional plans would have a positive impact in term of cost as the number of plans would be necessary less than twenty-eight plans and limited to the number of regions. In addition, the coordination at European level would decrease slightly the loss of load level compared to the regional coordination (EENS 0,01% compared to 0,02%).

On the contrary, on cybersecurity, the creation of a dedicated agency at EU level would have important economic implications as this agency would be a new body that does not exist yet and which is also not foreseen in the NIS Directive. The costs of creating this new agency are not only limited to the creation of a new agency itself, but the costs would also have to include the roll-out of a whole security infrastructure. For example, the estimated costs of putting in place the necessary security infrastructure and related services to establish a comparable national body - cross-sectorial governmental Computer Emergency Response Team (CERT) with the similar duties and responsibilities at national level as the planned pan-European sector-specific agency - would be approximately 2.5 million EUR[41] per national body. This means that the costs for the security infrastructure would be manifold for a pan-European body. In terms of human resources, for the proper functioning of the new agency with minimum scope and tasks at EU level, it is estimated a staff of 168 full time equivalents (considering 6 full time equivalents per Member State sent to the EU agency). The representation from all Member States in the agency is essential in order to ensure trust and confidence on the institution. However, the availability of network and information security experts who are also well-versed in the energy sector is limited.

Who should be affected and how

The obligation of regional plans would have important implications for the competent authorities as the coordination and agreement of common issues (e.g. load shedding plan, harmonised definition of protected customers) would be a lengthy and complex process.

On cybersecurity, the creation of the new agency at EU level would mobilize highly qualified human resources with skills in both energy and information and communication technologies (ICT). This could have a potential impact on national administrations and energy companies as long as some of the experts in the field could be recruited by the new institution. However, the impact would be limited as the representation for all Member States should be guaranteed. Therefore, a small number of experts (around 6) per country could be recruited.

Impact on business and public authorities

Overall Option 3 would imply significantly administrative impact in the preparation of the regional plans. It would require important efforts to gather information related to national and regional circumstances and contribute to the joint task of assessing the risks and identifying the measures to be included in the plans. In any case, it would seem difficult to coordinate within a region the national specificities and risks originate mostly in one Member State.

The creation of a new agency on cybersecurity would imply significant administrative impacts in the preparation and set-up of the agency, as well as in the communication structure with already existing cross-sectorial bodies of Member States (CERTs/CSIRTs).

Conclusion

From the point of view of impacts, particularly costs and administrative impact, Option 1 could in principle appear as preferred option. However, the performance in terms of effectiveness and efficiency is limited compared to Option 2 and 3. Additionally, impacts associated with Option 3 are neither proportionate nor fully justified by the effectiveness of the solutions, which makes Option 3 perform poorly in terms of efficiency compared to Option 2.

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[41] SWD(2013) 32 final.

Overall, the more harmonized approach to security of supply through minimum rules pursued by Option 1 would not solve all the problems identified, in particular, the uncoordinated planning and preparation ahead of a crisis. As regards Option 1, the main drawback of this approach is that each Member State would be drafting and adoption the national risk preparedness plans under its own responsibility. Given the urgency to enhance the level of protection against cyber threats and vulnerabilities, it must be concluded that Option 1 regarding cybersecurity is not recommended, because it is not viable for reaching the policy objectives, given that the effectiveness would depend on whether the voluntary approach would actually deliver a sufficient level of security.

Option 2 addresses many of the shortcomings of Option 1 providing a more effective package of solutions. In particular, the regionally coordinated plans ensure the regional identification of risks and the consistency of the measures for prevention and managing crisis situations. For cybersecurity this option creates a harmonised level of preparedness in the energy sector and ensures that all players have the same understanding of risks and that all operators of essential services follow the same selection criteria for the energy sector throughout Europe.

Overall, Option 3 represents a highly intrusive approach that tries to address possible risks by resorting to a full harmonisation of principles and the prescription of concrete solutions. The assessment of impacts in Option 3 shows that the estimated impact on cost is likely to be high and looking at the performance in terms of effectiveness, it makes Option 3 a disproportionate and not very efficient option.

In the light of the previous assessment, the preferred option would be Option 2. This option is the best in terms of effectiveness and, given its economic impacts, has been demonstrated to be the most efficient as well as consistent with other policy areas.

6.1.6. *Subsidiarity*

The necessity of EU action is based on the evidence that national approaches not only lead to sub-optimal measures, they also make the impacts of a crisis more acute. Additionally, the risk of a blackout is not confined to national boundaries and could directly or indirectly affect several Member States. Therefore, national actions in terms of preparedness and mitigation cannot only be defined nationally, given the potential impact on the level of security of supply of a neighbouring Member State and/or on the availability of measures to tackle scarcity situation.

The increasing interconnection of the EU electricity markets requires a coordination of measures. In the absence of such coordination, security of supply measures (including measures on cybersecurity) implemented at national level only are likely to jeopardize other Member States' or the security of supply at EU level. Situations like the cold spell of 2012 showed that coordination of action and solidarity are of vital importance. An action in one country can provoke risks of blackouts in neighbouring countries (e.g. electricity export limitations imposed by Bulgaria in February 2012 had an impact in the electricity and gas sectors in Greece). By contrary, coordination may offer a wider range of solutions.

So far, the potential for more efficient and less costly measures thanks to the regional coordination has not being fully exploited, which is detrimental to EU consumers.

However, the regional approach to security of supply also requires paying special attention to the divergences that between regions could appear. Therefore such coordinated approach requires action at the EU level. Action at EU level could be also needed under certain situations where the security of supply in the EU, cannot be sufficiently achieved by the Member States alone and can therefore, by reason of the scale or efforts of the action, be better achieved at Union level.

The EU action is framed under Article 194 of Treaty of the Functioning of the Energy Union (TFEU) which recognizes that certain level of coordination, transparency and cooperation of the EU Member states' policies on security of supply is necessary in order to ensure the functioning of the energy market and the security of supply in the Union.

6.1.7. *Stakeholders' Opinions*

The results of the *Public Consultation on Risk Preparedness in the area of Security of Electricity Supply* showed that the majority of respondents (companies, associations and Governments) take the view that the current legal framework (the SoS Directive) is not sufficient to address the interdependencies of an integrated European electricity market.

Assessments and Plans

A majority of stakeholders is in favour of requiring Member States to draw up risk preparedness plans (see as example the answers from the Dutch and Latvian Governments, GEODE, CEDEC, EDF UK, TenneT, Eurelectric and Europex).

Stakeholders also see a need for regional coordination of the assessment and preparation for rare/extreme risks (see for example the anwers of the Estonian, Finish, French, Dutch, Swedish Governments as well as ENTSO-E and Eurelectric). However, there is no agreement on how to 'define' regions for planning and cooperation. Most stakeholders suggest to use existing (voluntary) systems for regional cooperation as a staring point (e.g. the Finish Government) and emphasize the role of the existing RSCs (e.g. the Czech Government). Also the European Parliament[42] takes the view that it makes sense to step up cooperation within and between regions under the coordination of ACER and with cooperation of ENTSO-E, particularly as regards evaluating cross-border impacts.

Stakeholders further make the case for a common methodology for assessing risks to ensure comparability of results (e.g. EDF). This could be achieved through common high-level templates (e.g. answers from the Finish, Dutch, Norwegian Governments and the German Association of Local Utilities). There is general acknowledgement of the importance of preventing risks related to cyber-attacks.

Many stakeholders stress the need for a definition/clarification on roles and responsibilities as well as operational procedures to be followed (e.g. who to contact in times of crisis). Stakeholders see the added value of designating one 'competent authority' per Member States, however there is no agreement on who this should be.

[42] See: *Towards a New Energy Market Design* (June 2016), Werner Langen, European Parliament, paragraph 68.

Some argue that the choice should be left with the Member States (see for example the answers from the Norwegian Government or the German Association of Local Utilities) while others prefer a strong mandate of the TSOs (e.g. TenneT).

Crisis management

Stakeholders, in particular from the industry also request more transparency to reduce the scope for measures that unnecessarily distort markets. A majority of stakeholders sees a need for clear provisions on the suspension of market activities, "protected customers" and cost compensation (e.g. EDF).

Even though stakeholders point out that the draft Network Codes and current practice should be taken into account, they see a need for political discussion on regional level and the definition of clear principles for crisis management as e.g. curtailment in simultaneous scarcity situations requires political decision (e.g. ENTSO-E[43]). The need to develop a more common approach to managing crisis situations within the EU while taking into account the existing regional solutions is also seen by the Dutch Presidency of the European Council[44] and the Florence Forum[45].

Monitoring

In order to ensure adequate oversight, most stakeholders are in favour of a system of peer reviews to be conducted in a regional context or in the frame of the Electricity Coordination Group which could provide the interlinkage between technical and political/economical aspects. Monitoring could be further enhanced through more common and transparent approach to standards. Some stakeholders wish a stronger role for ACER/ENTSO-E and a rather facilitating role for the Commission (e.g. CEER, ENTSO-E)

[43] See for example *ENTSO-E's presentation on Capacity Mechanisms (TOP 2.4)* from the Florence Forum in June 2016, ENTSO-E (available: https://ec.europa.eu/energy/en/events/meeting-european-electricity-regulatory-forum-florence).

[44] See *Note to the Permanent Representatives Committee/Council: Messages from the Presidency on electricity market design and regional cooperation*, paragraph 7.

[45] See *Conclusions from Florence Forum*, March 2016, paragraph 10.

7. DETAILED MEASURES ASSESSED UNDER PROBLEM AREA 4: THE SLOW DEPLOYMENT OF NEW SERVICES, LOW LEVELS OF SERVICE AND POOR RETAIL MARKET PERFORMANCE

7.1. Addressing energy poverty

7.1.1. *Summary table*

Objective: Better understanding of energy poverty and disconnection protection to all consumers				
	Option: 0	**Option: 0+**	**Option 1**	**Option 2**
	BAU: sharing of good practices.	BAU: sharing of good practices and increasing the efforts to correctly implement the legislation. Voluntary collaboration across Member States to agree on scope and measurement of energy poverty.	Setting an EU framework to monitor energy poverty.	Setting a uniform EU framework to monitor energy poverty, preventative measures to avoid disconnections and disconnection winter moratorium for vulnerable consumers.
Energy poverty		EU Observatory of Energy poverty (funded until 2030).	Option 0+: EU Observatory of Energy Poverty (funded until 2030). Generic description of the term energy poverty in the legislation. Transparency in relation to the meaning of energy poverty and the number of households in a situation of energy poverty Member States to measure energy poverty. Better implementation of the current provisions.	Option 0+: EU Observatory of Energy Poverty (funded until 2030). Specific definition of energy poverty based on a share of income spent on energy. Member States to measure energy poverty using required energy. Better implementation and transparency as in Option 1.
Disconnection safeguards		NRAs to monitor and report figures on disconnections.	NRAs to monitor and report figures on disconnections.	NRAs to monitor and report figures on disconnections. A minimum notification period before a disconnection. All customers to receive information on the sources of support and be offered the possibility to delay payments or restructure their debts, prior to disconnection. Winter moratorium[46] of disconnections for vulnerable consumers.

46 An all season moratorium may be suitable to some MS but not necessarily to all. In addition, evidence on Excess Summer Death is less developed than for Excess Winter Deaths which makes it difficult to quantify the cost/benefits. Finally, stakeholders have noted that while in winter, heating is necessary, particularly if affected by bad health. Other cost effective

Pros	Continuous knowledge exchange.	Stronger enforcement of current legislation and continuous knowledge exchange.	Clarity on the concept and measuring of energy poverty across the EU.	Standardised energy poverty concept and metric which enables monitoring of energy poverty at EU level. Equip Member States with the tools to reduce disconnections.
Cons	Existing shortcomings of the legislation are not addressed: lack of clarity of the concept of energy poverty and the number of energy poor households persist. Energy poverty remains a vague concept leaving space for Member States to continue inefficient practices such as regulated prices. Indirect measure that could be viewed as positive but insufficient by key stakeholders.	Insufficient to address the shortcomings of the current legislation with regard to energy poverty and targeted protection.	New legislative proposal necessary. Administrative costs.	New legislative proposal necessary. Higher administrative costs. Potential conflict with principle of subsidiarity. Specific definition of energy poverty may not be suitable for all Member States. Safeguards against disconnection may result in higher costs for companies which may be passed to consumers. Safeguards against disconnection may also result in market distortions where new suppliers avoid entering markets where risks of disconnections are significant and the suppliers active in such markets raise margins for all consumers in order to recoup losses from unpaid bills. Moratorium of disconnection may conflict with freedom of contract.
Most suitable option(s): Option 1 is recommended as the most balanced package of measures in terms of the cost of measures and the associated benefits. Option 1 will result in a clear framework that will allow the EU and Member States to measure and monitor the level of energy poverty across the EU. The impact assessment found that the propose disconnection safeguards in Option 2 come at a cost. There is potential to develop these measures at the EU level. However, Member States may be better suited to design these schemes to ensure that synergies between national social services and disconnection safeguards can be achieved. Please note that Option 1 and Option 2 also include the measures described in Option 0+.				

solutions can be found for heatwave (drink water; staying indoors). We are aware that in some MS the housing stock is not prepared for heatwaves and houses are overheated. However, this may be better assessed at Member State level.

7.1.2. <u>Description of the baseline</u>

Energy has a fundamental role to ensure adequate households' standards of living. Energy services are crucial to ensure warm homes, water and meals, lighting, refrigeration and the operation of other appliances. European households are, however, increasingly unable to meet their basic energy needs due to energy prices increasing faster than household income and inefficient housing and household appliances leading to higher energy bills[47].

An affordable connection to energy supply facilitates modern daily life by providing essential services and enabling social interactions. Lack of access to an energy supply impinges on the rights of energy consumers and negatively affects living conditions and health[48]. This is well recognised in legislation[49] and reflected in the overall objectives of the European Internal Energy Market (IEM).

Under the existing provisions in the Electricity and Gas Directive, Member States have to address energy poverty where identified. The evaluation of the provisions found important shortcomings stemming from the opaqueness of the term *energy poverty*, particularly in relation to consumer vulnerability, and the lack of transparency with regards to the number of households suffering from energy poverty across Member States.

The aim of this Section is to describe the two policy areas impacted by the proposed options: <u>energy poverty</u> and <u>disconnection safeguards</u>.

Energy poverty: drivers of energy poverty and number of households in energy poverty

Energy poverty is often defined as the situation in which individuals or households are not able to adequately heat their homes or meet other required energy services at an affordable cost[50].

Energy poverty is usually discussed in the context of general poverty. Yet, households face widely varying costs to achieve the same level of warmth for reasons other than income, such as, energy efficiency of the dwelling or household's ability to interact with the market. In addition, an adequate level of energy is essential for citizens to function and actively participate in society[51].

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47 *Energy poverty and vulnerable consumers in the energy sector across the EU: analysis of policies and measures*. (2015). Insight_E.

48 COM (2015) *"A framework Strategy for a Resilient Energy Union with a Forward-looking Climate Change Policy"*

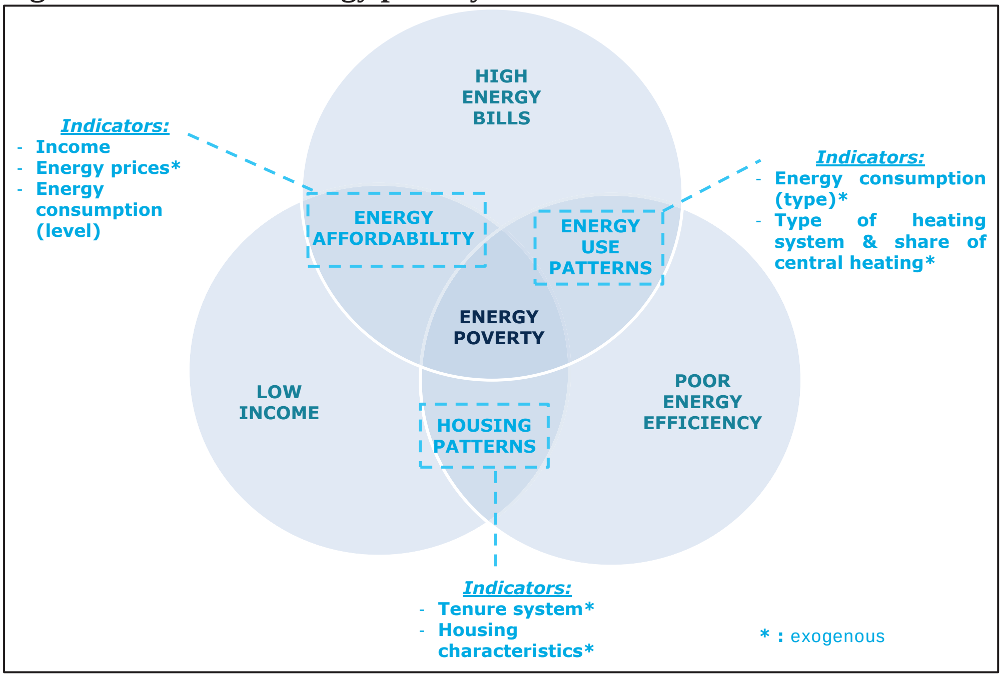
49 Directive 2009/72/EC Point 45 states that "Member States should ensure that household customers...enjoy the right to be supplied with electricity of a specified quality at clearly comparable, transparent and reasonable prices."

50 *Energy* poverty *and vulnerable consumers in the energy sector across the EU: analysis of policies and measures.* (2015). Insight_E.

51 *Fuel Poverty: The problem and its measurement*. 2001. John Hills. Available at: http://sticerd.lse.ac.uk/dps/case/cr/CASEreport69.pdf. *Working Paper on Energy Poverty*. 2016. Vulnerable Consumer Working Group. The Vulnerable Consumer Working Group (VCWG) provides

Insight_E identifies high energy bills, low income and poor energy efficiency as the main drivers of energy poverty[52].

Figure 1: Drivers of energy poverty



Source: Insight_E (2015)

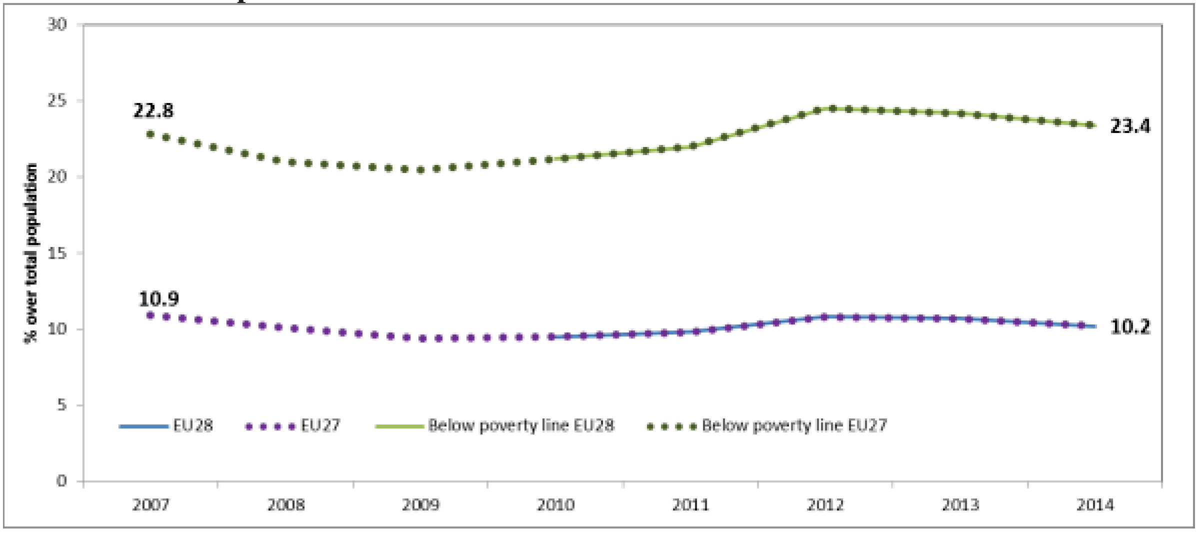
Looking at the drivers, it is likely that energy poverty impacts low-income households with higher energy needs. Eurostat publishes the number of households who felt unable to keep warm during winter. This indicator is widely used in the literature as a proxy indicator of energy poverty. In 2014, around 10% of the EU population was not able to keep their home adequately warm[53] (see Figure below).

advice to the European Commission on the topics of consumer vulnerability and energy poverty. Industry, consumer associations, regulators and Member States representatives are members of the group.

52 *Energy poverty and vulnerable consumers in the energy sector across the EU: analysis of policies and measure*s. (2015). Insight_E.

53 The indicator is measured as part of the Eurostat Survey on Income and Living Conditions (EU-SILC).

Figure 2: Percentage of all households and households in poverty that consider they are unable to keep warm



Source: Eurostat – SILC indicators (Inability to keep home adequately warm - Code: ilc_mdes01)

Evidence suggests that energy poverty is increasing in Europe. In recent years, energy prices have risen faster than household disposable income[54], which has been particularly problematic for low-income households, who depending on their individual circumstances, may have had to under-heat their homes, reduce consumption on other essential goods and services or get into debt to meet their energy needs[55].

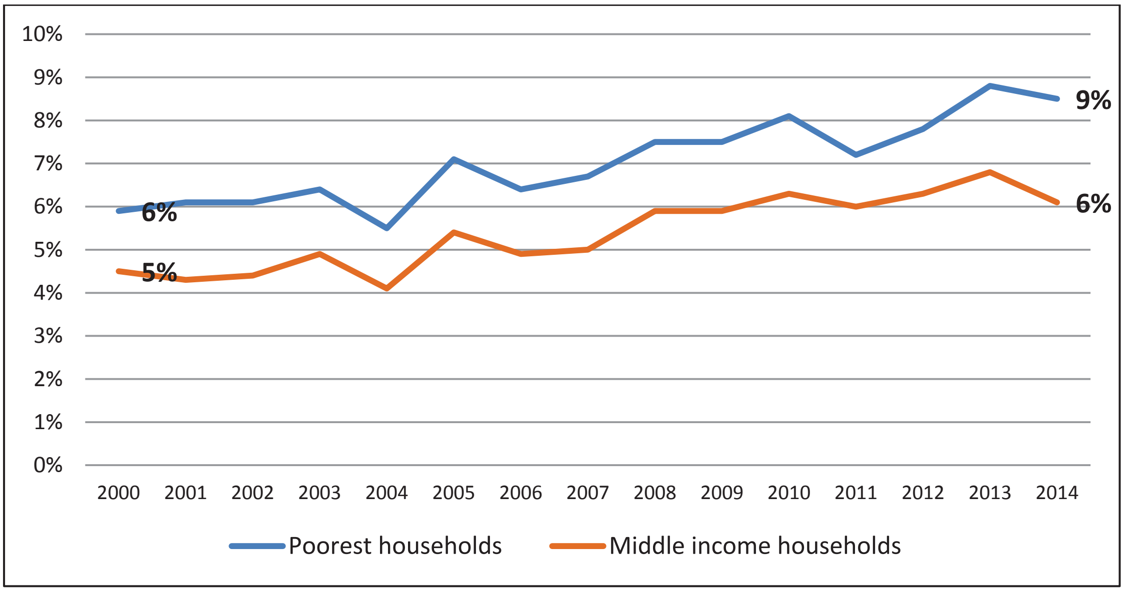
Data from Member States on household energy consumption shows that the poorest households have seen their share of disposable income spent on gas, electricity and other fuels used for domestic use[56] increased more than middle-income households. The Figure below presents the EU share of household expenditure on domestic energy between 2000 and 2014.

54 Source: Eurostat (Electricity prices for domestic consumers; Gas prices for domestic consumers; disposable income of households per capita; period 2010 – 2014).

55 *Working Paper on Energy Poverty*. 2016. Vulnerable Consumer Working Group.

56 Domestic use refers to heating, lighting and powering appliances.

Figure 3: EU average - share of households' budget spent on domestic energy services



Source: National Statistical Authorities of EU Member States; VCWG (2016)

In 2014, expenditure on energy services for the poorest households in the EU increased by 50%, reaching almost 9% of their total budget.

Preliminary analysis for the upcoming Energy Price and Cost Report indicates that in most of the EU Member States the share of energy in total expenditure grew faster in the lowest income quintile than in the third quintile, implying that increasing energy costs impacted poorer households more significantly than those on middle income. For instance, the EU average spending for households in the lowest income quintile on electricity and gas increased by 24% in real terms. As a comparison, middle income households saw their domestic energy expenditure increase by 18% in real terms.

The lack of affordability of domestic energy services, which can be understood as a proxy for energy poverty, can have serious consequences on households' well-being.

The Marmot Review highlighted the strong relationship between colder homes, Excess Winter Deaths (EWDs) and increased incidence of other health problems. The review found that 22% of EWDs in the UK could be attributed to cold housing. Healy[57] found that countries with the poorest housing (Portugal, Greece, Ireland, the UK) show the highest excess winter mortality.

The Figure below presents EWD[58] for the EU Member States in 2014. The Figure shows that deaths in winter are significantly higher than during the rest of the year, particular for some Member States.

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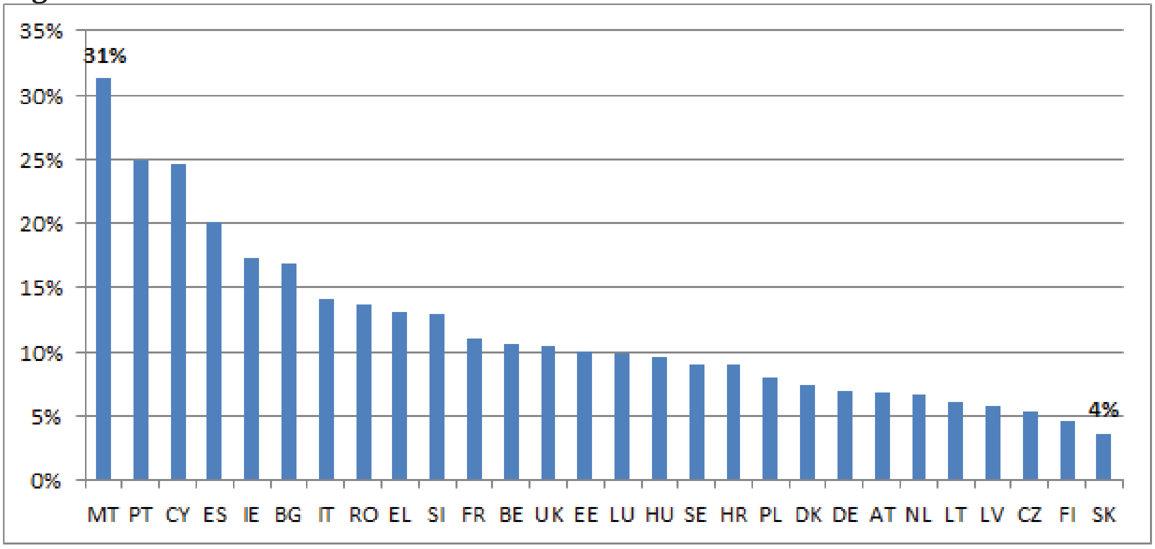
57 *Excess winter mortality in Europe: a cross country analysis identifying key risk factors*. (2003). Healy.

58 *Excess Winter Deaths* = {[winter death (December – March)]- 0.5[Non-winter deaths (August – November, April – July]} / (average of non-winter deaths)

Figure 4: Excess Winter Deaths – 2014



Source: EU Buildings Database (BPIE)

In addition to the negative impacts on health, energy poverty can result in high level of indebtedness or even disconnection. At the EU level, energy poverty risks excluding some consumers from the energy transition, preventing them from enjoying the benefits of the IEM.

The issue of energy poverty or lack of affordability of domestic energy services is likely to remain relevant. In a scenario where energy prices follow GDP growth while wages, especially for low-income workers remain flat, the gap between household income and energy prices will widen and energy poverty is likely to increase. There are two main channels through which wages for low-skilled workers may be supressed:

- Automation: routine tasks which are usually carried out by low-skilled workers can be automated as technology allows. As the cost of technology falls, low-skilled wages may be supressed to compete with capital[59].
- Skill-bias innovation: modern economics rely on a more educated workforce. As demand for skilled individuals increases, it decreases the demand for unskilled workers and their wages[60]

These effects combined are likely to supress wages, making affordability of energy services more difficult for low-income households and, as a result, increase the number of households in energy poverty.

Disconnection safeguards: protecting energy poor and vulnerable consumers

[59] *Unemployment and Innovation*, No 20670, NBER Working Papers. 2014. Stiglitz.
[60] "*Skills, Tasks and Technologies: Implications for employment and earnings*", No 16082, NBER Working Papers. 2010. Acemoglu and Autor.

The evaluation identified that given the rising levels of energy poverty. Member States may have been discouraged to phase out regulated prices. Regulated prices, however, have negative implications on consumers, hindering competition and innovation[61].

The evaluation recommended that any future legislative change could look into reinforcing EU assistance on energy poverty proposing appropriate tools for addressing energy poverty which support Member States' efforts to phase-out regulated prices[62]. Article 3 of the Electricity Directive[63] and Gas Directive [64] markets reinforces the role of consumer protection and the additional need for protection of vulnerable consumers through particular measures, referring to the prohibition of electricity (and gas) in critical times as one option.

Disconnections in electricity or gas supply to residential households typically arise out of non-payment and can become especially problematic for households struggling to keep up with their bills. In addition, there may be a disproportionately negative impact on households with children or elderly residents in terms of health, education, etc.

In what follows, we provide an overview of the number of households being disconnected and the main disconnection safeguards applied by Member States.

Overview of electricity and gas disconnections in the EU

Disconnection rates vary significantly across Member States. Figure 5 indicates that the higher the disconnection level, as can be expected, the higher the arrears on utility bills[65], which increases when the income falls below 60% of the median income. Similar disconnection levels (Malta, Denmark, France, and Austria) exhibit similar levels of arrears on utility bills. However, there are some exceptions: UK, Lithuania, Belgium and Luxembourg have relatively high arrears and low disconnection rates.

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61 A detail description of the negative impacts of regulated prices and the Member States currently applying some kind of price regulation mechanism is included in Annex on Price Regulation

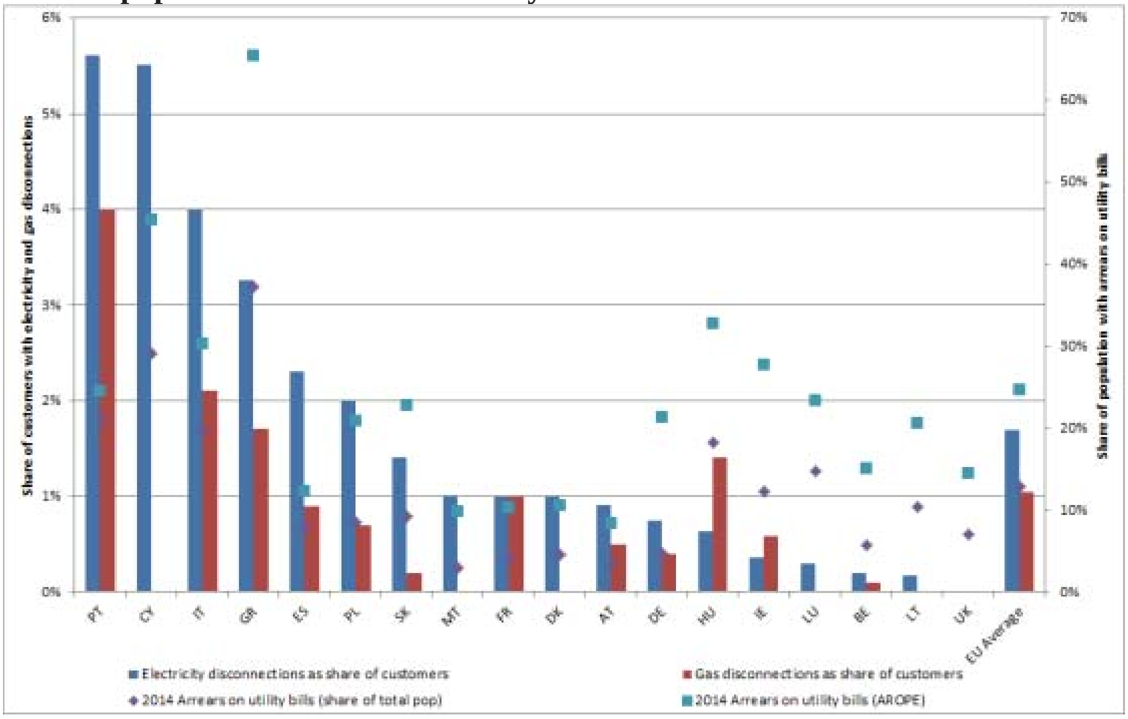
62 All energy consumers explicitly have a number of rights including a right to an electricity connection, choice of and ability to switch supplier, clear contract information and right of withdrawal, and accurate information and billing on energy consumption, vulnerable customers should receive specific protection measures to ensure adequate protection.

63 "*Member States shall take appropriate measures to protect final customers, and shall, in particular, ensure that there are adequate safeguards to protect vulnerable customers. In this context, each Member State shall define the concept of vulnerable customers which may refer to energy poverty and, inter alia, to the prohibition of disconnection of electricity to such customers in critical times. Member States shall ensure that rights and obligations linked to vulnerable customers are applied. In particular, they shall take measures to protect final customers in remote areas.*"

64 Directive 2009/73/EC of the European Parliament and the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (OJ L 211, 14.8.2009, p. 94).

65 Eurostat EU-SILC 2014

Figure 5: Share of customers with electricity disconnections, gas disconnection, and share of population in arrears on utility bills



Source: Insight_E (Forthcoming); Data: Eurostat; CEER National Indicators Database 2015

The rate of electricity disconnections, where the data is available, is highest across the southern European Member States that have arguably been hardest hit by recessionary effects of the recent economic downturn[66]. In fact, in those Member States, households exhibit the highest shares of debt on utility bills.

In terms of gas disconnections, where the data was reported, Portugal, Italy, Greece and Hungary exhibit the highest levels of gas disconnections followed by France, Spain, Poland, Austria, Germany and Slovakia.

Disconnection safeguards: a classification of measures

Disconnection safeguards represent one of the measures that Member States implement to protect energy consumers. These measures ensure consumers have a continuous supply of energy. Such safeguards can be applied to the entire customer base or to specific groups, such as vulnerable consumers.

Disconnection safeguards can be grouped into four key measures, which can take the form of direct protection measures, such as disconnection prohibitions, and / or other

[66] "*Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers*". Forthcoming publication. Insight_E.

complementary associated measures such as debt management, and customer engagement. See Table below[67].

Table 1: Summary of disconnection safeguards

Measure	Description
Disconnection prohibition	Moratorium on disconnecting the energy supply (either electricity, gas or both) for all customers, a specific target group or time period (e.g., Winter)
Debt management	Debt management can include a negotiated a payment plan, delayed payment responsibility or a financial grant to assist with costs.
Customer engagement	Customer engagement typically involves communication between the energy supplier and the customer, where either the customer contacts the energy supplier for assistance or the energy supplier is required to engage with the customer before commencing the actual disconnection.

Source: Insight_E (Forthcoming)

Member States use a combination of these measures to prevent consumers from disconnection. A summary of those is reported in Table 2.

[67] "*Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers*". Forthcoming publication. Insight_E.

Table 2: Disconnection protection safeguards by Member States

Measures		Focus	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LV	LU	MT	NL	PL	PT	RO	SE	SK	SI	UK
Disconnection prohibition	year-round measures	All consumers																						EG						
		Vulnerable consumers/low income/socio-demographic				E			E			EG	EG	EG		EG			EG					EG		E				
		Consumers with (or at risk of) medical conditions				E				EG	E	EG		EG		EG							EG				E		E	
		Services (such as public lighting, hospitals and transport)									EG						E													
		Unemployed consumers								EG		EG		EG																
		Under bill dispute settlement																E			E		EG	EG	EG		E			
	Seasonal measures (Winter or certain days of the week)	All consumers		EG						EG								E					EG							
		Vulnerable consumers/low income/socio-demographic										EG	EG	EG		EG	EG		EG							EG			E	EG
		Consumers with (or at risk of) medical conditions										EG				EG	EG													
Complementary measures		Debt management	LV	LV		L	L	LV			LV		L	V		L	L	L			L	L	L	L			L		L	L
		Prepaid meters	LV	L				LV									L	L			L			L						L
		Customer engagement	LV	LV				LV	L		LV		L				L	LV			LV			L	L	L	LV	L		V
Statistics		Elec Discon per 1000 customers	9.1	1.5		55.1		7.5	10.0		23.0		10.0	32.6		6.3	3.6	40.0	1.8		3.0	10.0		20.0	56.1			14.0		0.0
		Prepaid meters per 1000 customers	1.4	46.0		0.0		0.4			0.0		0.0	0.0		0.0	0.0	0.0	0.0		0.0	0.0		15.1	0.0			0.0		12.0

E	**electricity**	**G**	**gas**	**L**	**legislated**	**V**	**voluntary**

Source: CEER National Indicators Database 2015, INSIGHT_E Country Reports 2015

Disconnection safeguards - disconnection prohibition

Disconnection prohibitions are non-financial measures where moratoriums on disconnections are declared, often for specific customer groups or for specific time periods. These include measures that forbid disconnection to all customers or a target group, or measures that allow disconnection only after certain stringent steps have been taken. Prohibition can apply at particular times of the year (e.g., Winter), target particular socio-demographic characteristics (e.g., either defined through the official definition for “vulnerable consumer” or target households with elderly or children), where this would have a negative impact on health, to customers in a legitimate complaint process, or to a situation where a country is going through a national economic crisis[68].

Nineteen states have either year-round or seasonal disconnection prohibition. Disconnection prohibition is legislated exclusively all year-round for specific customer groups in seven Member States (Cyprus, Denmark, Spain, Luxembourg, Poland, Portugal, Sweden), two Member States offer seasonal disconnection prohibition only (Belgium, UK) and eleven Member States offer both year-round and seasonal disconnection prohibition to varying customer groups (Estonia, Finland, France, Greece, Hungary, Ireland, Italy, Lithuania, Netherlands, Romania and Slovenia).

Only four Member States provide blanket coverage for consumers in relation to disconnection protection, but only on a seasonal basis (Belgium, Estonia, Italy, and the Netherlands). Other widely protected consumers are those with (or at risk of) medical conditions (in ten Member States - Cyprus, Estonia, Spain, Finland, Greece, Hungary, Ireland, the Netherlands, Sweden, Slovenia), and customers currently under dispute settlements (in six Member States - Italy, Luxembourg, the Netherlands, Poland, Portugal, Sweden).

Disconnection safeguards - debt management

Debt management can include non-financial arrangements such as counselling or assistance with budgeting as well as financial arrangements including a negotiated payment plan, delayed payment responsibility or a financial grant to assist with costs. In some instances, this is a measure that regulators or energy suppliers are required to offer, whereas in other Member States, this can be offered either voluntarily through a government agency, an energy supplier, or other consultation bodies.

The use of debt management measures is legislated in 17 Member States (Austria, Belgium, Cyprus, Czech Republic, Germany, Spain, France, Hungary, Ireland, Italy, Luxembourg, Malta, the Netherlands, Poland, Sweden Slovenia, and UK), while four Member States (Austria, Belgium, Germany, Spain) also implement additional voluntary measures, whereas Greece implements only voluntary measures for debt management.

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68 "*Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers*". Forthcoming publication. Insight_E.

Disconnection safeguards - customer engagement

Customer engagement typically involves communication between the energy supplier and the customer, where either the customer contacts the energy supplier for assistance or the energy supplier is required to engage with the customer before commencing the actual disconnection.

Energy consumers have a right to clear and transparent billing information and a single point of contact, whose role is to ensure that consumers receive all the information that they need regarding their rights.

Some form of customer engagement is implemented in 15 Member States (Austria, Belgium, Germany, Denmark, Spain, France, Ireland, Italy, Luxembourg, Poland, Portugal, Romania, Sweden, Slovakia, and UK). Limited information is available on how the various energy companies choose to engage with customers, but a review of the regulators showed that the legislation usually ensures that consumers are notified about their bills or an impending disconnection usually in the form of a letter[69].

Finally, 22 Member States combine the use of debt management and some form of customer engagement including: Austria, Belgium, Cyprus, Czech Republic, Germany, Denmark, Spain, France, Greece, Hungary, Ireland, Italy, Luxembourg, Malta, the Netherlands, Poland, Portugal, Romania, Sweden, Slovakia, Slovenia and UK.

On the other hand six Member States do not have debt management or customer engagement safeguards either in their legislation or voluntarily and include Bulgaria, Estonia, Finland, Croatia, Lithuania and Latvia.

Disconnection notification periods and procedures for disconnection and reconnection across Member States

Even if the time frames differ among Member States, the practice for disconnecting and reconnecting customers to electricity and gas provision is similar. The general practice in most Member States consists of at least one (or more) written notices of unpaid bills, followed by disconnection. Both the days between the unpaid bill and the final notice of disconnection, and between the latter and the disconnection are usually legislated[70].

The number of days before disconnection varies among Member States (Figure 6). The disconnection period is the highest in Belgium with a lengthy disconnection process[71], followed by the UK. Both Belgium and the UK have the lowest share of customers disconnected from electricity. The explanation for such low disconnection levels might be in the fact that those two states have the highest requirements in terms of days before disconnection is legally possible, but could also be linked to the fairly high share of

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[69] CEER National Indicators Database 2015

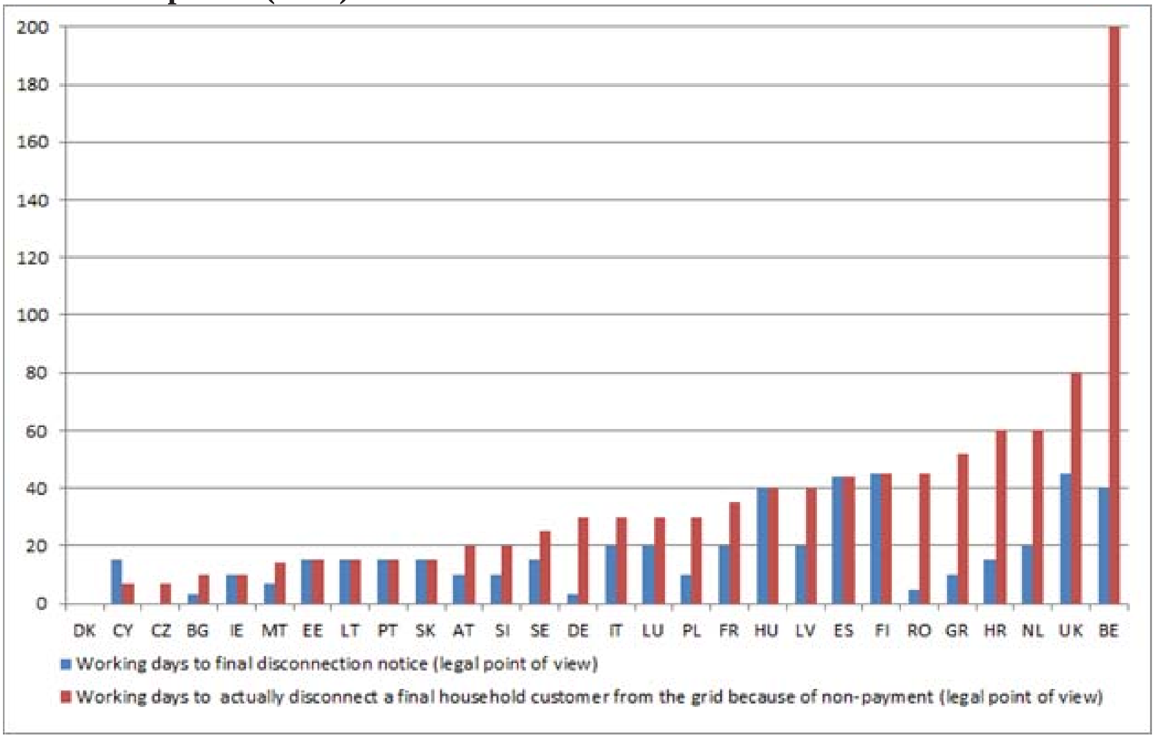
[70] *"Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers"*. Forthcoming publication. Insight_E.

[71] Upon defaulting on payments, a customer is given at least 30 day notice of cancellation of the contract, followed by a 60 day grace period to find another supplier. If the customer defaults on payments with the second supplier, this process is repeated. Thereafter, the supplier can apply to the local council for permission to disconnect the customer, especially if they refuse the installation of a prepaid meter.

prepaid meters and strong use of complementary measures. Denmark does not have a specific number of days legislated, but rather specifies that at least two notifications must be sent out[72].

Certain Member States (e.g., Sweden and Luxembourg) contact the social services in between the final notice period and the disconnection of a consumer. Other Member States have longer disconnection times where a smart meter is in place (e.g., in Italy before the disconnection takes place, the maximum power supply is reduced to 15% for 15 days[73]).

Figure 6: Working days before electricity disconnection, in ascending order for notification period (2014)



Source: Insight_E (Forthcoming)

Reconnection happens in most Member States only upon receipt of payment of the entire outstanding debt to the service provider or when an alternative repayment plan has been negotiated. In some Member States, the customer is reconnected if the unpaid bill is disputed. In those cases, the service provider cannot disconnect the customer again until the dispute is settled.

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72 *"Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers"*. Forthcoming publication. Insight_E.

73 *"Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers"*. Forthcoming publication. Insight_E.

7.1.3. *Deficiencies of the current legislation*

This Section summarises Section 7.1.1 and Annex III of the Commission evaluation of the provisions on consumer vulnerability and energy poverty in the 2009 Electricity and Gas Directives. The full evaluation is included in a separate document.

The legislators' original objectives of these provisions were:

1. To ensure protection of vulnerable consumers by having Member States define the concept of vulnerable consumers and implement measures to protect them.
2. To mitigate the problem of energy poverty by having Member States address energy poverty, where identified, as an issue.

These provisions were put in place to facilitate the decision by Member States to proceed with electricity and gas market liberalisation, as it was recognised by the legislators that actions to protect vulnerable consumers were needed in the context of liberalising the European energy market.

The evaluation assesses the legislation against five criteria. The Table below provides a summary of this assessment.

Table 3: Evaluation of the provisions on consumer vulnerability and energy poverty

Criterion	**Legislation meets criterion**	**Assessment**	
		Achievements	*Shortcomings*
Effectiveness	Partially	Member States define vulnerable consumer and adopt measures to protect them.	Uneven protection of vulnerable consumers. Lack of data on the scale and drivers of energy poverty Growing energy poverty levels across the EU Lack of assistance by Member States to address energy poverty. NRA lack data to fulfil monitoring role. Some Member States still quote energy poverty as a reason for maintaining price regulation and not going ahead with full energy market liberalisation
Efficiency	Completely	Low costs compared with potential benefits.	
Relevance	Completely	Consumer vulnerability will remain relevant as some drivers of vulnerability are permanent.	Energy poverty likely to grow in the future if no policy adopted.
Coherence	Partially	No inconsistencies with or elements working against objectives of the provisions.	Lack of an agreed description of the term energy poverty and caveats in the obligations stand in contrast to the call for action in the Directive.
EU-added value	Completely	Member States have taken action as a result of EU intervention.	

Source: Evaluation of the provisions on consumer vulnerability and energy poverty

The evaluation concluded that the provisions in the Electricity and Gas Directive related to consumer vulnerability and energy poverty were mostly **effective**.

EU action successfully encouraged Member States to define the concept of vulnerable consumers in their legislation and to adopt measures to protect vulnerable consumers. The provisions have also brought the issue of energy poverty to the attention of Member States.

However, the evaluation also identified certain shortcomings. With respect to energy poverty, the evaluation shows that even though most Member States have correctly implemented the provisions on consumer vulnerability, the incidence of energy poverty has continued to rise across the EU. In addition, even though Member States have to address energy poverty where identified, the Electricity and Gas Directives do not include any reference to the meaning of energy poverty nor do they explain in which circumstances energy poverty can be identified as an issue.

At the same time current legislation does not enable comparable data on energy poverty to be sourced from Member States to deliver a full picture of energy poverty in the EU, in terms of scale, drivers and potential future evolution. In addition, while the provisions on vulnerable consumers and energy poverty were put in place to facilitate the decision by Member States to proceed with electricity and gas market liberalisation, 17 Member States still maintain electricity and/or gas price regulation, often quoting increase in energy poverty as a risk associated with deregulating energy prices.

While research indicates that energy poverty and consumer vulnerability are two distinct issues[74], the provisions in the Electricity and Gas Directives refer to energy poverty as a type of consumer vulnerability. The evaluation argues that this may have led to an incorrect expectation that a single set of policy tools could address both problems simultaneously.

The evaluation also identifies shortcomings in the effectiveness of the provisions referring to the role of National Regulatory Authorities (NRAs) in monitoring electricity and gas disconnections.

The evaluation found that the provisions were **efficient** and **relevant**. While efficiency was difficult to quantify due to lack of data, it is likely that the benefits derived from defining consumer vulnerability at the Member State level and implementing measures to protect them outweighed the costs of setting up such policies. In terms of relevance, evidence suggests that the problem of energy poverty is growing and it is likely to continue without policy intervention. European Commission[75] research suggests that consumer vulnerability in the energy market will continue to be a relevant policy issue in the future as a substantial share of those characterised as vulnerable consumers have permanent characteristics that make them vulnerable.

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[74] *"Energy poverty and vulnerable consumers in the energy sector across the EU: analysis of policies and measures"*. (2015). Insight_E.

[75] European Commission (2016). Available at: http://ec.europa.eu/consumers/consumer_evidence/market_studies/vulnerability/index_en.htm-summit/2015/files/ener_le_vulnerability_study_european_consumer_summit_2015_en.pdf.

Regarding **coherence**, there were no inconsistencies or elements in the legislation working against the objectives of the provisions on vulnerable and energy poor consumers. Nevertheless the misidentification of consumer vulnerability and energy poverty as the same issue in the Electricity and Gas Directives means that the expected combined impacts are not occurring and energy poverty grows while Member States take action to protect vulnerable consumers.

In relation to **EU-added value**, while it is true that some Member States had been already protecting their vulnerable energy consumers prior to EU intervention, others have been obliged to take action as a result of EU intervention.

Overall, the evaluation concluded that the provisions have mostly met their objectives. However, the legislation did not give sufficient attention to the issue of energy poverty. As the Electricity and Gas Directives define energy poverty as a type of consumer vulnerability, the effectiveness of the provisions was reduced. This categorisation leads to a simplistic expectation that a single set of policy measures from Member States would automatically address both problems simultaneously. However, evidence suggests that energy poverty has been rising over the years, despite the protection available for vulnerable consumers. In parallel, Member States have maintained regulated prices, which had a negative effect on the internal energy market.

The Options presented in this impact assessment attempt to address this situation.

7.1.4. *Presentation of the options.*

This Section presents the policy options in detail. Each Option includes a table with the description of the specific measures. An assessment of the costs and benefits for each of the measures is presented in the following Section.

Business as Usual (BaU): sharing of good practices.

The BaU includes measures that are currently implemented or in the pipeline. These measures will be undertaken without legislative change and aim at improving knowledge-exchange.

Table 4: BaU

	Measures	Pros	Cons
Energy poverty	Promoting good practices	Continuous Knowledge exchange.	Existing shortcomings of the legislation are not addressed: lack of clarity of the concept of energy poverty and the number of energy poor households persist. Energy poverty remains a vague concept leaving space for Member States to continue inefficient practices such as regulated prices. Indirect measure that could be viewed as positive but insufficient by key stakeholders.

The Commission has already secured funding to set up an Observatory of Energy Poverty. However, the BaU scenario assumes the funding for the Observatory will not be extended beyond 2019 and therefore no additional cost will be incurred in the appraised period.

The Commission will continue promoting the exchange of good practices which are likely to contribute to enhance transparency and knowledge dissemination. However, this option may be insufficient to address the partial effectiveness of the current provisions as identified in the evaluation as the current legislation does not require Member States to measure energy poverty and hence to address it.

Option 0+: sharing of good practices and monitoring the correct implementation of the legislation.

There is scope to address some of the problems identified in the evaluation without new legislation. This option seeks non-legislative measures such as voluntary collaboration across Member States as a tool to address these problems. With the help of the EU Observatory of Energy poverty, this option includes voluntary collaboration across Member States to agree on the scope of energy poverty as well as the way of measuring. Measures to ensure the monitoring of disconnections across Member States are also included.

The evaluation identified that National Regulatory Authorities (NRAs) have not reported to ACER data on the number of disconnections. As described in the evaluation, ACER reported that only 16 NRAs were able to report data on disconnections. This is despite the legal obligation stated in the Electricity Directive Article 37 *Duties and powers of the regulatory authority* under paragraphs (j)[76] and (e)[77].

In addition, the Observatory delivers the exchange of good practices and better statistical understanding of the drivers of energy poverty. Option 0+ assumes the Observatory continues its operation at least until 2030 (the end of the assessment period for the Impact Assessment).

Table 5: Option 0+

	Measures	Pros	Cons
Energy poverty	EU Observatory of Energy Poverty. NRAs to monitor and report data on disconnections. Voluntary collaboration across Member States to agree on scope and measurement of energy poverty.	Stronger enforcement of current legislation and continuous knowledge exchange.	Insufficient to address the shortcomings of the current legislation with regard to energy poverty and targeted protection.

This option does not address all the shortcomings identified in the evaluation, such as the need to measure energy poverty and the lack of adequate tools to protect vulnerable and energy poor consumers. Furthermore, voluntary collaboration may not be a suitable measure. The Commission already undertakes actions involving Member States, such as the publication of guidelines and working paper in the context of the Vulnerable

[76] Monitoring the level and effectiveness of market opening and competition at wholesale and retail levels, including on electricity exchanges, prices for household customers including prepayment systems, switching rates, disconnection rates, charges for and the execution of maintenance services, and complaints by household customers, as well as any distortion or restriction of competition, including providing any relevant information, and bringing any relevant cases to the relevant competition authorities;

[77] Reporting annually on its activity and the fulfilment of its duties to the relevant authorities of the Member States, the Agency and the Commission. Such reports shall cover the steps taken and the results obtained as regards each of the tasks listed in this Article;

Consumer Working Group, with have had a limited impact on Member States. Thus, legislative action, beyond Option0+, is required.

Option 1: Setting an EU framework to monitor energy poverty.

This option includes obligations on Member States that will need to be implemented through new EU legislation. The measures included in this option are designed to address the shortcomings identified in the evaluation:

- clarifying the concept of energy poverty,
- improving transparency with regard to the number of households in energy poverty.

Table 6: Option 1

	Measures	Pros	Cons
Energy poverty	Generic, adaptable description of the term energy poverty in the legislation. Member States to measure energy poverty.	Shared understanding of what energy poverty entails while flexible enough to cater for Member States' differences. Transparency when measuring and monitoring energy poverty. Synergies with the Observatory.	New legislation will be necessary. Administrative impact on Member States.

Option 1 includes a number of legislative changes that represent new obligations for Member States. In what follows, we provide a detailed description of these new obligations.

Energy poverty - a description of the term energy poverty

Option 1 adds a description of the term energy poverty in the EU legislation. The objective of this measure is to clarify the term energy poverty.

A number of European institutions have called on the European Commission to propose an EU-wide definition of energy poverty, calling for a common description of the term energy poverty.

- EESC (2011; 1)[78]: *"... energy poverty should be tackled at all tiers of government, and that the EU should adopt a common general definition of energy poverty, which could then be adapted by Member States"*.
- Committee of the Regions (2014;15)[79] *"...recognition of the problem at the political level on the one hand, and to ensure legal certainty for measures to combat energy poverty on the other; such a definition should be flexible in view of the diverse circumstances of the Member States and their regions…"*.

78 European Economic and Social Committee (EESC) (2011) Opinion of the European Economic and Social Committee on *'Energy poverty in the context of liberalisation and the economic crisis'* (exploratory opinion). Official Journal of the European Union, C 44/53.

79 Committee of the Regions (CoR) (2014) Opinion of the Committee of the Regions - *Affordable Energy for All*. Official Journal of the European Union, C 174/15.

- European Parliament (2016)[80] *" Calls on the Commission to develop with stakeholders a common definition of energy poverty which should aim at assessing at least the following elements: material scope, difficulty for a household to gain access to essential energy, affordability and share of total household cost, impact on basic household needs such as heating, cooling, cooking, lighting and transport".*
- European Parliament (2016)[81] *"Calls for the development of a strong EU framework to fight energy poverty, including a broad, common but non-quantitative definition of energy poverty, focusing on the idea that access to affordable energy is a basic social right"*

Thomson et al[82] summarise the arguments in favour and against of an EU-wide definition of energy poverty.

Table 7: Arguments in favour and against an EU-wide definition of energy poverty

In favour	Against
Policy synergy. Not all Member States are addressing this problem and those that are, act on their own, without seeking synergies with others, which makes it harder to identify, assess and deal with energy poverty at the European level.	Limited evidence. Need to compile comparable household data on energy consumption and income to produce reliable statistics.
Recognition. A common EU-level definition of energy poverty may give the problem better visibility at the Member State level.	Comparability. A shared pan-EU definition would need to be relatively broad in order to accommodate the diversity of contexts found at the Member State-level, in terms of climate conditions, socioeconomic factors, energy markets and more.
Clarification. Adopting even a general description of fuel or energy poverty at the EU-level would help to resolve the considerable terminological confusion that presently exists, and may pave the way for more detailed national definitions.	Path dependency. An incorrect definition may lead Member States to a wrong path from which it may be difficult to depart as a result of path dependency.

Source: Thomson et al (2016)

The Vulnerable Consumers Working Group (VCWG)[83] looked into several definitions used to describe energy poverty which have been put forward by Member States, European institutions and research projects. Most of the definitions shared common themes:

- domestic energy services refer to services such as heating, lighting, cooking and powering electrical appliances;
- the term affordable is used to refer to households receiving adequate energy services without getting into debt; and

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[80] *European Parliament. Committee on Employment and Social Affairs. Draft report on meeting the antipoverty target in the light of increasing household costs*. (2015/2223(INI)). Rapporteur: Tamás Meszerics.

[81] *European Parliament. Committee on Industry, Research and Energy. Draft report on Delivering a New Deal for Energy Consumers*. (2015/2323(INI)). Rapporteur: Theresa Griffin.

[82] *Fuel poverty in the European Union: a concept in need of definition?* 2016. Thomson et al.

[83] *Working Paper on Energy Poverty*. 2016. Vulnerable Consumer Working Group.

- the term adequate usually means the amount of energy needed to ensure basic comfort and health.

VCWG concluded that a prescriptive definition of energy poverty for the EU28 would be too restrictive, given the diverse realities across Member States. Yet, the group agreed that a generic definition represents a positive step forwards to tackle the problem of energy poverty. The VCWG argues that, if such as EU-wide definition were to be identified, it should be simple, focus on the problem of affordability and allow sufficient flexibility to be relevant across Member States[84]. Such a definition can refer to elements such as households with a low-income; inability to afford; and adequate domestic energy services. Within the generic definition Member States can adapt it to suit national circumstances (e.g. by adopting their own numerical threshold for low income).

Energy poverty - Measuring energy poverty

Option 1 requires Member States to measure energy poverty. To measure energy poverty, Member States will need to construct a metric which should make reference to household income and household domestic energy expenditure.

Measuring energy poverty allows Member States to understand the depth of the problem and assess the impact of the policies to tackle it[85].

Most researchers used Eurostat Survey on Income and Living Conditions (EU-SILC) to produce proxy indicators of energy poverty at Member State level such as the perceived inability to keep homes adequately warm[86]. However, this indicator has some well-known limitations[87] [88]:

- subjectivity due to self-reporting;
- limited understanding of the intensity of the issue due to the binary character of the metric;
- assumption that participants in a survey view such judgments like 'adequacy of warmth' in a similar way; and
- difficult to compare across Member States.

In Member States that have or are considering energy poverty metrics, most experiences concern expenditure-based metrics rather than consensual-based metrics. The advantage of an expenditure based metric is that it is quantifiable and objective. These indicators measure energy poverty as a result of two of the main drivers of energy poverty: domestic energy expenditure and household income. Nonetheless, these indicators also suffer from some limitations[89]:

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[84] A few Member States already have a definition of energy poverty. These definitions are presented in Sub-Annex 1.

[85] *Working Paper on Energy Poverty*. 2016. Vulnerable Consumer Working Group.

[86] This kind of indicators is referred in the academic literature as consensual-based indicators.

[87] Selecting Indicators to Measure Energy Poverty. 2016. Trinomics.

[88] "*Quantifying the prevalence of fuel poverty across the European Union"*. 2013. Thomson and Snell.

[89] *"Selecting Indicators to Measure Energy Poverty"*. 2016. Trinomics.

- cannot assess whether consumers reduce expenditure because of budget constraints or due to other factors. Thus, it does not take account of the issue of self-disconnection i.e. households who do not consume adequate amount of energy to avoid falling into arrears or debt;
- it does not reflect consumers' motivation for expenditure levels; and
- sensitive to methodological decisions such as definition of income or the definition of the threshold.

Member States will have the freedom to define the metric according to their circumstances. A European Commission study reviewed 178 indicators of energy poverty and proposed a final set of four indicators, three of them expenditure based metrics. The study confirmed that all the final recommended indicators can be produced using data already collected by Member States[90].

These measures build upon the existing provisions on energy poverty in the Electricity and Gas Directive. They offer the necessary clarity to the term energy poverty, as well as, the transparency with regards to the number of household in energy poverty. Since currently available data can be used to measure energy poverty, the administrative costs are limited. Likewise, the actions proposed do not condition Member States primary competence on social policy, hence, respecting the principle of subsidiary.

[90] Trinomics 2016. Available at: https://ec.europa.eu/energy/sites/ener/files/documents/Selecting%20Indicators%20to%20Measure%20Energy%20Poverty.pdf

Option 2: Setting a uniform EU framework to monitor energy poverty, preventative measures to avoid disconnections and disconnection winter moratorium for vulnerable consumers.

Table 8: Option 2

	Measures	Pros	Cons
Energy poverty	- Specific, harmonised definition of energy poverty. - Require Member States to measure energy poverty using required energy.	- Improve comparability of energy poverty as a result of a harmonised concept of energy poverty. - Measuring energy poverty using required energy.	- New legislation will be necessary. - A prescriptive definition of energy poverty may not be adequate for all Member States. - High administrative cost to measure energy poverty using required energy.
Safeguards against disconnection	- A minimum notification period before a disconnection. All customers to receive information on the sources of support and be offered the possibility to delay payments or restructure their debts, prior to disconnection. - Winter moratorium of disconnections for vulnerable consumers.	- Equips Member States with the tools to prevent and reduce the number of disconnections. - Gives customers more time to make arrangements to pay their bills, i.e. avoids unnecessary disconnections and costs of disconnecting and reconnecting. - Customers are given information. about outreach points. - Customers are given an opportunity to better handle their energy debts - The most vulnerable customers will benefit from a guaranteed energy supply through the coldest months of the year.	- New legislation will be necessary. - Administrative impact on Member States. - Administrative impact on energy companies - Safeguards against disconnection may result in higher costs for companies which may be passed to consumers. - Safeguards against disconnection may also result in market distortions as suppliers seek to avoid entering markets where there are likely to be significant risks of disconnections and the suppliers active in such markets raise margins for all consumers in order to recoup losses from unpaid bills. - Moratorium of disconnection may conflict with freedom of contract.

Option 2 represents additional obligations for Member States. In what follows, we describe these new obligations.

Energy poverty - EU definition of energy poverty

Option 2 adds a specific definition of energy poverty in the EU legislation. Energy poverty will refer to those households which after meeting their required energy needs fall below the poverty line or other income related threshold. This measure will clarify the term energy poverty (as in Option 1) and improve the comparability and monitoring of energy poverty within the EU.

A definition using a relative income threshold, such as the Low Income High Cost[91], is suited to measure energy poverty in the EU. Since the poverty threshold is a relative metric (e.g. below 40% of the median income) this type of metric takes account of the distribution of income in each Member State. However, it might well be that in some Member States a significant number of households live below the poverty line. In those cases, a different metric of energy poverty using a lower income threshold may be more suitable.

Some stakeholders will be in favour of such as measure since it addresses the need for a common definition. However, as it was described in Option 1, the EESC (2011: 1) and Committee or the Regions (2014;15) request the Commission a *'common general definition'* ; *'flexible in view of the diverse circumstances of the Member States and regions*'. The VCWG[92] also stated that *'a prescriptive definition of energy poverty for the EU28 would be too restrictive, given the diverse realities across Member States'*.

Similar arguments were put forward in Thomson et al[93] with regard to comparability. The authors argue that a shared pan-EU definition would need to be relatively broad in order to accommodate the diversity of contexts found at the Member State level in terms of climate conditions, socioeconomic factors or energy markets. This is in contradiction with a more prescriptive definition of energy poverty at the EU level.

Energy poverty - measuring energy poverty

Option 2 requires Member States to measure energy poverty using *'required energy'*. Metrics using *'required'* rather than *'actual'* expenditure calculate the amount of energy necessary to meet certain standards such as a specific indoor temperature during a number of hours per day.

The main advantage of this type of measurement[94] is that it refers to an adequate level of energy service. As such, it computes the amount of energy for a specific heating regime rather than measuring actual expenditure, which may not be adequate for low-income households that may under-consume due to budget constraints.

In order to be able to compute required energy, the following information is needed[95]:

- heating system and fuels used;
- dwelling characteristics;
- regional and daily climate variations; and
- number of days per year a household stays in their home.

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91 *"Low income High Costs (LIHC) indicator"* (Hills, 2011): A household i) income is below the poverty line (taking into account energy costs); and ii) their energy costs are higher than is typical for their household type.

92 *Working Paper on Energy Poverty*. 2016. Vulnerable Consumer Working Group.

93 *"Fuel poverty in the European Union: a concept in need of definition?"* 2016. Thomson et al.

94 The UK, which has considerable experience in this field, measures energy poverty or fuel poverty using required energy.

95 *Selecting Indicators to Measure Energy Poverty*. 2016. Trinomics.

This data, especially the variables related to dwelling characteristics, are rarely available. To collect it, Member States are likely to need to run a Housing Condition Survey[96] which ideally should be linked to the Household Budget Survey.

Safeguards against disconnection - minimum notification period of 40 working days

Evidence suggests that stronger guidelines dictating adequate disconnection times and procedures could be an effective way to prevent disconnections. For instance, in Belgium and UK, the two countries with the highest disconnection time requirements, disconnection levels are at the lowest[97] .

This measure requires Member States to give all customers at least two months (approximately 40 working days) notice before a disconnection from the first unpaid bill.

In Member States, legislated working days before disconnecting a customer vary between a week and 200 days, with an average of approximately 40 days (See Table below).

Table 9: Statistics on disconnection notices (legal requirements) in Member States

	MIN	MAX	Average	Standard deviation
Working days to final disconnection notice[98]	3	45	18.15	12.87
Working days to actually disconnect a final household customer from the grid because of non-payment	7	200	36.81	36.79

Source: Insight_E (Forthcoming); Data: Eurostat; CEER National Indicators Database 2015

Longer disconnection period may stop some disconnections as customers have more time to engage or to seek help. The direct monetary benefit comes in the form of avoided disconnection and reconnection costs to society. Other non-direct monetary benefits to the utility are those of retaining the customer, and avoiding lost income, due to allowing the consumer time to pay back arrears.

It is possible to calculate the amount of time before which it is not cost effective to disconnect a household from electricity and gas provision. This is done by comparing the cost of disconnection and reconnection with the average monthly household expenditure for gas and electricity.

Figure 7 shows the number of days it is cost-effective not to disconnect a household for those Member States with available data to perform the necessary calculations.

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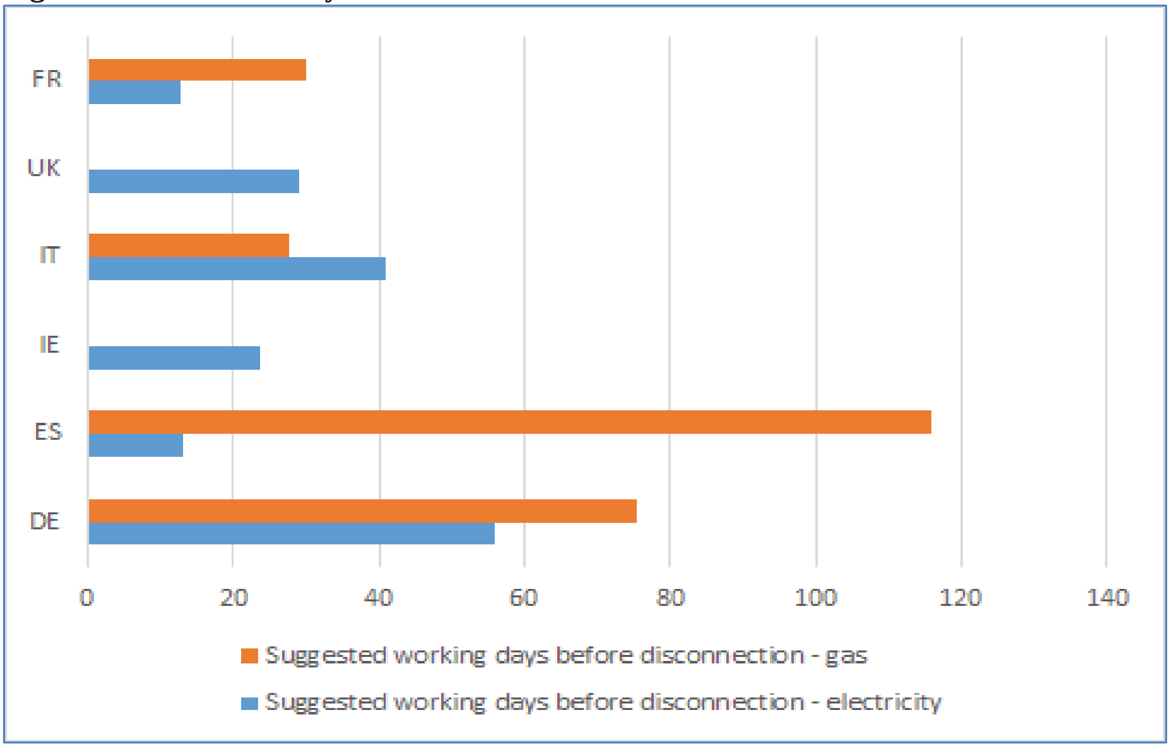
96 The Housing Condition Survey measures the physical characteristics of the dwelling such as height of the ceilings, materials of the wall, or the size of the windows to calculate the energy performance of the building.

97 "*Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers*". Forthcoming publication. Insight_E.

98 Denmark does not stipulate a number of days but rather that a minimum of two notices be sent

Figure 7: Number of days from which it is cost-effective to disconnect a household



Source: Insight_E (Forthcoming)

Interestingly for both electricity and gas it is not cost effective to disconnect within a certain time starting from the unpaid bill for any of the considered countries. For electricity, in Germany and Italy, it is cost-effective to disconnect only after approximately 2 months from the unpaid bill, while in Ireland and the UK at least one month is needed to justify disconnection. That value is approximately 15 working days for France and Spain, having less costly connection and reconnection procedures. For gas, as the cost of connection and reconnection is higher, those values are larger. In Germany and Spain three or more months of unpaid bills would justify a disconnection, for Italy and France more than one month[99].

It is to be noted that these numbers merely compare the cost of connecting and disconnecting a household with household energy bills. Including other social and health benefits would increase the amount of days before a disconnection is cost effective. Those costs are difficult to quantify. Nonetheless, a number of articles and research projects provide evidence of a link between warmer homes and improvements in health[100][101][102][103] [104] [105]. More information on the benefits of a longer notification period is provided in the next Section.

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[99] *"Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers"*. Forthcoming publication. Insight_E

[100] *Chilled to Death: The human cost of cold homes*. (2015). Association for the Conservation of Energy, Available at: http://www.ukace.org/wp-content/uploads/2015/03/ACE-and-EBR-fact-file-2015-03-Chilled-to-death.pdf

Setting a minimum notification period of 40 working days will lead to 18 Member States having to increase their disconnection notice requirements (See Table below). Five of those would have to increase the notice by 10 working days or less. Hungary, Latvia, Spain, Finland, Romania, Greece, Croatia, the Netherlands, UK and Belgium would not be impacted by this regulation. In addition, Member States with robust social security schemes disconnection safeguards would not have any substantial impact as early intervention typically assists vulnerable consumers and the energy poor with avoiding disconnections, nota bene via direct financial support.

The extension of the disconnection notice period is associated with additional costs for the suppliers in the form of bills which can be left unpaid by some of the customers. The measure also has potential market distortion effects as suppliers seek to avoid entering markets where there are likely to be significant risks of disconnections and the suppliers active in such markets raise margins for all consumers in order to recoup losses from unpaid bills.

Table 10: Additional working days with a two month disconnection notice[106]

Member State	Additional number of days
Cyprus	33
Czech Republic	33
Bulgaria	30
Ireland	30
Malta	26
Estonia	25
Lithuania	25
Portugal	25
Slovakia	25
Austria	20
Slovenia	20
Sweden	15
Germany	10
Italy	10
Luxembourg	10
Poland	10
France	5

Source Insight_E (Forthcoming); Data: Eurostat; CEER National Indicators Database 2015

Safeguards against disconnection – prior to disconnection notice, consumers should receive: (i) information on the sources of support and (ii) be offered the possibility to delay payments or restructure their debt.

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101 *"Fuel Poor & Health. Evidence work and evidence gaps"*. DECC. Presented at Health, cold homes and fuel poverty Seminar at the University of Ulster. (2015). Cole, E. Available at: http://nhfshare.heartforum.org.uk/HealthyPlaces/ESRCFuelPoverty/Cole.pdf

102 *Towards an identification of European indoor environments' impact on health and performance - homes and schools*. (2014). Grün & Urlaub.

103 Excess winter mortality: a cross-country analysis identifying key risk factors. Journal of Epidemiology & Community Health 2003. Healy.

104 *Estimating the health impacts of Northern Ireland's Warm Homes Scheme 2000-2008*. (2008). Liddell.

105 *The Health Impacts of Cold Homes and Fuel Poverty* (London: Friends of the Earth). (2011). Marmot Review Team.

106 Denmark does not stipulate a number of days but rather that a minimum of two notices be sent

Customer engagement

Customer engagement typically involves communication between the energy supplier and the customer, where either the customer contacts the energy supplier for assistance or the energy supplier is required to engage with the customer before commencing the actual disconnection. This communication can take the form of a letter, registered letter, e-mail, phone call, text message or house call. The use of these measures varies across Member States and while a comprehensive review of how this is undertaken is not available, it is clear that some variation of consumer engagement occurs nonetheless.

Debt management

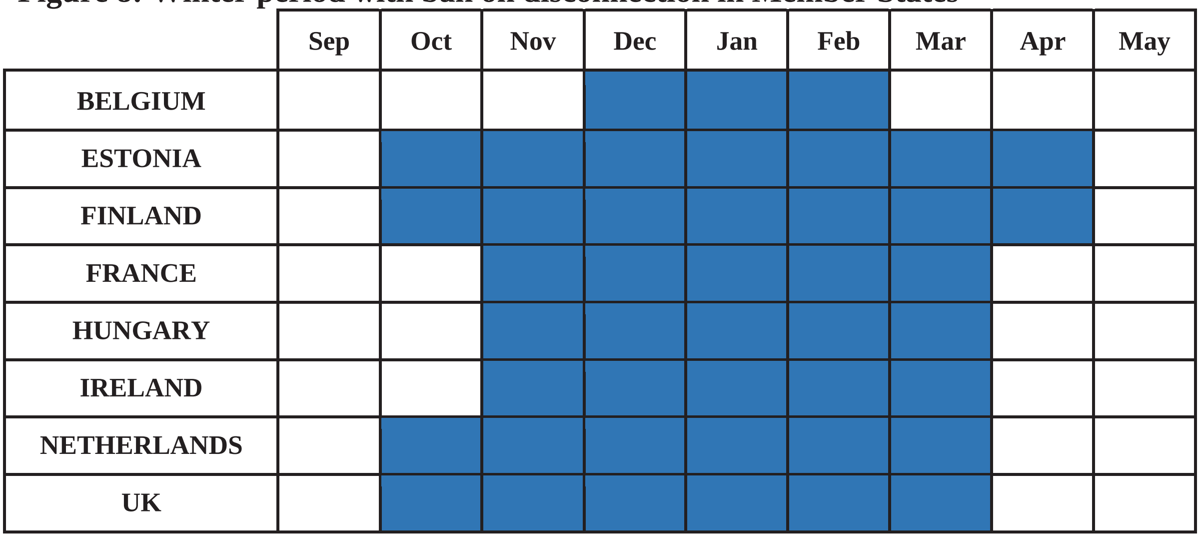
Debt management can include non-financial arrangements such as counselling or assistance with budgeting as well as financial arrangements including a negotiated payment plan, delayed payment responsibility or a financial grant to assist with costs.

Safeguards against disconnection - winter moratorium of disconnections for vulnerable consumers.

This measure stops disconnection from energy provision (electricity and gas), for vulnerable consumers, during the winter months. Already, 10 Member States provide seasonal disconnection prohibitions at particular times.

Of those Member States, eight define clearly the winter period during which disconnections are banned (See Figure 8).

Figure 8: Winter period with ban on disconnection in Member States



Source: Insight_E (Forthcoming)

On the other hand, other countries define the winter as ‘cold season’ or depending on temperatures (e.g. Lithuania prohibit disconnections when the highest daily air temperature is lower than minus 15 °C or higher than plus 30 °C).

This measure, unlike the others, will specifically target vulnerable consumers. Hence, the coverage of the measure depends on the definition of consumer vulnerability in energy markets in each of the Member States.

With regard to the disconnection safeguards discussed in this Section, it needs to be noted that Member States may be better suited to design these schemes to ensure that synergies between national social services and disconnection safeguards can be achieved. These synergies may also result in public sector savings which may be significant given the substantial costs of some of these measures, see Table 22 and Table 23.

7.1.5. *Comparison of the options*

This Section quantifies the costs and benefits for the BaU and each of the policy options. The tables below summarise the main results of the Cost Benefit Analysis (CBA). The methodology, assumptions and calculations are subsequently explained.

Table 11: BaU: costs and benefits

	Costs		Benefits	
	Description	Quantification	Description	Quantification
Promoting good practices.	Exchange of good practices and collaboration across Member States	EUR 0.	Continuous Knowledge exchange.	N.A. only qualitative.

Table 12: Option 0+: costs and benefits

	Costs		Benefits	
	Description	Quantification	Description	Quantification
EU Observatory of Energy Poverty.	Running the EU Observatory of energy poverty.	EUR100,000 per year .	Knowledge exchange.	N.A. only qualitative.
NRAs to monitor and report figures on disconnections.	Better implementation of current legislation Electricity Directive Article 37 (j) and (e).	No additional cost.	Improved information on number of disconnections.	N.A. only qualitative.

Table 13: Policy Option 1: costs and benefits

	Costs		Benefits	
	Description	Quantification	Description	Quantification
Energy poverty				
Generic adaptable description of the term energy poverty in the legislation.	Enumerate the main characteristics that define energy poverty.	No additional cost.	Transparency, clarification and policy synergies.	N.A. only qualitative.
Member States to measure energy poverty.	Produce a metric to measure energy poverty.	Administrative cost.	Understanding the extent of the problem. Improved transparency.	N.A. only qualitative.

Note: Policy Option 1 includes the measures described in option 0+.

Table 14: Policy Option 2: costs and benefits

	Costs		Benefits	
	Description	Quantification	Description	Quantification
Energy poverty				
Specific definition of energy poverty	Produce a specific harmonised definition of energy poverty.	No additional cost.	Transparency, clarification and policy synergies.	N.A. only qualitative.
Member States to measure energy poverty using required energy	Collecting detailed housing stock data.	Administrative cost.	Understanding the extent of the problem. Improved transparency.	N.A. only qualitative.
Disconnection safeguards				
A minimum notification period before a disconnection.	All customers will receive a disconnection notice at a minimum of at least two months (or 40 working days) before disconnection from the first bill unpaid.	Cost of unpaid bills.	General benefits from avoiding disconnection in the form of improvements in households' health and well-being; cross-departmental savings; and avoiding cost of disconnection and reconnection. Gives customers more time to make arrangements to pay their bills.	N.A. only qualitative.
All customers to receive information on the sources of support and be offered the possibility to delay payments or restructure their debts, prior to disconnection.	Prior to issuing a disconnection notice, all consumers should: receive: (i) information on the sources of support, and; (ii) be offered the possibility to delay payments or restructure their debt.	Consumer information cost varies depending on the type of intervention which may include registered letters; phone calls; text message; or emails. Debt management cost depends on the type of intervention.	General benefits from avoiding disconnection. Gives customers more time to make arrangements to pay their bills, i.e. avoids unnecessary disconnections and costs of disconnecting and reconnecting. Customers are given information about outreach points. Customers are given an opportunity to better handle their energy debts	N.A. only qualitative.
Winter moratorium of disconnections for vulnerable consumers.	In case of non-payment vulnerable consumers will not be disconnected from the electricity and gas grid during Winter.	The cost of unpaid bills.	General benefits from avoiding disconnection. The most vulnerable customers will benefit from a guaranteed energy supply through the coldest months of the year.	N.A. only qualitative.

Note: Policy Option 2 includes the measures described in option 0+.

Methodology

The methodology follows the Better Regulation Guidelines. In this Section, we present the steps taken for the calculation of the costs and benefits.

Introduction - Costs and Benefits Analysis (CBA)

This impact assessment takes account of societal costs and benefits when assessing the impact of the policies. In addition, the net impact on total welfare and the net impacts on specific groups (i.e. winners and losers) are relevant as these provisions are likely to benefit more those in lower income or vulnerable economic conditions.

The cost of the measures occurs immediately following the adoption of the policies into national legislation and are borne by public authorities (i.e. measuring energy poverty) and energy providers (e.g. disconnection safeguards). Benefits, on the other hand, tend to emerge over a longer time frame and are more difficult to quantify.

As far it has been possible, costs and benefits are based on market prices. However, this has not always been possible, particularly when quantifying the benefits.

In the case of disconnection safeguards, the costs of this measure represent the mirror image of the benefits for those households who are not disconnected as a result of the safeguards. Even though this is a symmetrical change in private welfare and therefore it cancels out at the aggregate level, there is an impact in terms of transfer of welfare between those who are not in risk of disconnection (wealthier households) and those in risk of disconnection (poorest households). It can be argued that this transfer has a positive impact on efficiency if we assume poorest household have a higher marginal utility for each additional euro received than wealthier households. This approach has been followed in some Impact Assessments[107] using empirical evidence from the academic literature[108]. Due to lack of data, however, these effects have not been quantified.

The discount rate used equals 4%. The time period starts when the measures are implemented at Member State level and ends in 2030. We assume measures are implemented in 2020[109]. In reality, the starting period may be subject to change depending on which year the measures are approved in each Member State. This will advance or delay the costs and benefits impacting the overall net benefit of the policies.

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[107] UK Treasury *'Green Book Appraisal and Evaluation in Central Government* (2003). Annex 5 Distributional Impacts. Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/220541/green_book_complete.pdf

[108] Cowell and Gardiner (1999); Pearce and Ulph (1995)

[109] We assume the legislation proposed in the Winter Package will be approved by the co-legislator in 2017 and Member States will require three years for implementing the new measures.

As stated in the Better Regulation guidelines, CBA has important limitations. The main limitations refer to:

- the assumption that income can be a proxy for happiness or satisfaction,
- the fact that it willingly ignores distributional effects; and
- its lack of objectivity when it comes to the selection of certain parameters (e.g. the inter-temporal discount rate), which can tilt the balance in favour of certain regulatory options over others.

The overall goal of the intervention is to achieve the benefits at the overall lowest cost. The policy options will contribute to advancement in social welfare in terms of economic efficiency, consumer protection and life satisfaction.

Quantifying the costs

Producing a description of energy poverty (policy Option 1); and a specific definition of energy poverty (policy Option 2) will be undertaken by the European Commission at no additional cost.

Business as Usual – calculating the costs

<u>Exchange of good practices</u>

The European Commission continues fostering the exchange of good practices across Member States through its network of stakeholders such as the Vulnerable Consumers Workings Group. No additional cost is estimated.

Option 0+ – calculating the costs

<u>The cost of the EU Observatory of Energy Poverty</u>

The European Commission has published a contract service to build and maintain the EU Observatory of Energy Poverty. The current budget equals EUR 800,000 for a 40 month contract. The continuation of the work after the contract is estimated at EUR 100,000 per year[110].

<u>The cost of NRAs monitoring and reporting figures on disconnections</u>

The current energy legislation requires national regulators to monitor disconnections. However, not all Member States report figures on disconnections[111]. Full implementation of the current legislation represents no extra cost as there is no additional obligation.

Policy Option 1 – calculating the costs

<u>The cost of Member States to measuring energy poverty making reference to household income and household energy expenditure</u>

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110 "*Selecting Indicators to Measure Energy Poverty*". (2016). Trinomics.
111 *ACER Market Monitoring Report* (2014)

Measuring energy poverty will result on a new information obligation for Member States. This is a direct cost related to compliance i.e. the need to divert resources to address the direct consequences of the policy options which creates an administrative cost[112] to comply with the new information obligation.

The administrative costs consist of two different cost components: the business-as-usual costs and administrative impacts. The administrative impacts stem from the part of the process which is done solely because of a new legal obligation.

To compute these costs we follow the Better Regulation Guidelines which state that the effort of assessment should remain proportionate to the scale of the administrative costs imposed by the legislation and must be determined according to the principle of proportionate analysis.

To calculate the administrative cost we use the Standard Cost Model. The main objective of the model is to assess the cost of information obligations imposed by EU legislation.

The following Table presents the steps that will need to be followed to measure energy poverty.

[112] Administrative costs are defined as the costs incurred by enterprises, the voluntary sector, public authorities and citizens in meeting legal obligations to provide information on their action or production, either to public authorities or to private parties.

Table 15: Steps to measuring energy poverty

Activity	
Identification of information obligations	Measuring energy poverty making reference to household income and household energy expenditure. Data requirements: household income and household energy expenditure. Source: Household Budget Survey and/or Survey of Income and Living Conditions.
Identification of required actions	<u>Familiarising with the information obligation</u>: senior managers will need to assess the information needed and allocate tasks within the Civil Service to measure energy poverty. <u>Training employees about the information obligation</u>: civil servants will need training on the necessary data to measure energy poverty. The amount of training necessary is likely to be limited since the information needed (i.e. household income and household energy expenditure) is already collected by Member States. <u>Retrieving relevant information from existing data</u>: civil servants will need to retrieve household income and household energy expenditure data either from the Household Budget Survey and/or Survey on Income and Living Condition. <u>Producing new data</u>: civil servants will need to use household income and household energy expenditure to produce an indicator of energy poverty. For those Member States with no official metric to measure energy poverty, it is likely that the Civil Service will produce different metrics and recommend one for adoption. The work required to produce the most common indicators of energy poverty is not particularly burdensome[113]. <u>Holding meetings</u>: senior civil servants will hold several meetings to decide which metric should be used to measure energy poverty. Ultimately a decision will need to be made at the Government level before the metric is reported to the European Commission. <u>Inspecting and checking</u>: civil servants will need to perform quality control activities on the data to ensure the robustness of the results. <u>Submitting the information</u>: civil servants will need to submit the information to the European Commission. It is likely that in some cases civil servants may need to allocate additional time for discussion with European Commission officials for clarification.
Identification of target group	Public Authorities
Identification of frequency of required actions	Once a year
Identification of relevant cost parameters	No particular relevant cost such as external costs (e.g. using consultancies or gathering new data) has been identified.
Assessment of the number of entities concerned	28 Member States

The administrative impact will decrease after the first year since Member States will be familiar with the new obligation and have agreed on the internal procedures to measure

[113] *"Selecting Indicators to Measure Energy Poverty"*. (2016). Trinomics.

energy poverty. Hence, we have computed the administrative impact for year 1 and the administrative impact for the subsequent years separately.

An estimation of the time and frequency of the tasks was gathered from information provided by Member States.

France, the UK and Ireland already measure energy poverty. Hence, this obligation will not constitute an additional cost for these Member States.

To quantify the administrative impact we used the Standard Cost Model. The model does not include information for Croatia. The cost of measuring energy poverty in Croatia was calculated using information on labour cost from Slovenia. Even though this is not ideal, we prefer this approach to avoid any under-estimation of the cost of the obligation. At the EU level, the relative small size of Croatia means that the EU wide cost will not be significantly affected by this assumption. The final cost is shown in the Table below.

Table 16: Cost of measuring energy poverty making reference to household income and household energy expenditure (EUR)

	First year	Following years
Standard Cost Model	EUR 454,129	EUR 255,277
Estimated cost in France, UK, Ireland	(-EUR57,137)	(-EUR32,444)
Estimated cost in Croatia	EUR 10383	EUR 5788
Final cost	EUR 407,375	EUR 228,621

Source: European Commission's calculation

For completeness, we include the results of the Standard Cost Model in the tables below. These results include the cost of measuring energy poverty in all Member States but Croatia.

Table 17: Administrative costs of measuring energy poverty in year 1

Obligation	Action	Target Group	Staff type	Hourly rate	Man hours	Activity cost (EUR)
Measuring energy poverty	Familiarizing with the information obligation	28 MS	Legislators, senior officials and managers	41.5	65	75,530
	Training employees about the information obligations	28 MS	Professionals	32.1	33	29,660
	Retrieving relevant information from existing data	28 MS	Professionals	32.1	50	44,491
	Adjusting existing data	28 MS	Professionals	32.1	25	22,470
	Producing new data	28 MS	Professionals	32.1	143	128,079
	Holding meetings	28 MS	Legislators, senior officials and managers	41.5	52	60,424
	Inspecting and checking	28 MS	Professionals	32.1	31	27,638
	Copying	28 MS	Professionals	32.1	50	44,940
	Submitting the information	28 MS	Professionals	32.1	23	20,897
					Total	454,129

Source: European Commission's calculation

Table 18: Administrative costs of measuring energy poverty in following years

Obligation	Action	Target Group	Staff type	Hourly rate	Man hours	Activity cost (EUR)
Measuring energy poverty	Familiarizing with the information obligation	28 MS	Legislators, senior officials and managers	41.5	27	31,374
	Training employees about the information obligations	28 MS	Professionals	32.1	29	26,065
	Retrieving relevant information from existing data	28 MS	Professionals	32.1	33	29,660
	Adjusting existing data	28 MS	Professionals	32.1	12.5	11,235
	Producing new data	28 MS	Professionals	32.1	45	40,446
	Holding meetings	28 MS	Legislators, senior officials and managers	41.5	26	30,212
	Inspecting and checking	28 MS	Professionals	32.1	33	29,660
	Copying	28 MS	Professionals	32.1	45	40,446
	Submitting the information	28 MS	Professionals	32.1	18	16,178
					Total	255,277

Source: European Commission's calculation

Option 2 – calculating the costs

The cost of Member States measuring energy poverty using required energy

The UK measures energy poverty using required energy rather than actual expenditure. Social and physical surveys are carried out in each constituent country to gather all the necessary information to estimate and monitor energy poverty.

The European Commission requested the assistance of the Scottish Government to gather the necessary information to understand the activities and estimate the costs of measuring energy poverty using required energy. The estimated cost for using this approach at the EU level is based on the cost of an analogous exercise to measure energy poverty in Scotland.

The main tool to gather all the data to estimate the level of energy poverty in Scotland is the Scottish House Condition Survey[114] (SHCS). The objective of the survey is much broader than measuring energy poverty. The survey includes a range of additional topics, as well as information on several characteristics of the household. Each year a Technical Report[115] is published to summarise the survey methodology and delivery of the survey work.

The SHCS includes a sample of more than 3,000 paired households and dwellings. The Table below breaks down the different components of the SHCS. Member States already undertake social surveys[116], making the physical survey the main additional cost of this measure.

Table 19: SHCS – cost structure

SHCS – Activities	Description of activities	SHCS – Share of total cost
Survey management	Project management, recruitment, briefing and training, etc.	15%
Fieldwork costs - Social surveys - Physical survey	45 minutes social interview and 60 minutes physical survey, and work to secure interviews.	 24% 33%
Processes and final output	Data processing, sampling, selection, questionnaire development, validation, clean datasets, and survey reports.	24%
Estimating energy poverty	Energy poverty modelling using information collected in the surveys	4%

Source: European Commission's calculation

The methodology to calculate cost of gathering data to measure energy poverty using required energy at EU level is as follows:

[114] The Scottish House Condition Survey run as a standalone survey every 5 years, in 1991, 1996, and 2002. In 2004 it became an annual survey, running separately until 2011. From 2012, the SHCS was merged with the Scottish Household Survey.

[115] "*Scottish Household Survey Technical Report*". Available at: http://www.gov.scot/Topics/Statistics/SHCS/2009techrep

[116] For instance, physical surveys can be run as a sub-sample of larger surveys such as the Household Budget Survey which will significantly reduce the costs.

1. Calculate the cost per interview.
2. Adjust cost per interview by Member States labour costs.
3. Multiply cost per interview in each Member States by the number of effective interviews necessary to get a representative sample in each Member States.

Based on the information provided by the Scottish Government, we estimate the cost of the SHCS per interview to be around EUR 268. This cost includes the activities described in the Table above: survey management; fieldwork cost (physical survey); processes and final output; and estimating energy poverty.

A significant component of that cost relates to labour costs. Thus, we adjust the cost per interview by the different labour costs across the EU using information on wages provided in the Standard Cost Model. As previously mentioned, the model does not contain labour costs for Croatia. As before, we approximate Croatian labour costs using the labour cost in Slovenia.

The total number of households that would need to be interviewed depends on several statistical considerations. We use the effective sample size of the Household Budget Surveys[117] provided by Eurostat.

117 Eurostat Household Budget Surveys 2010 Achieve Sample Sizes. Quality Report. Source: http://ec.europa.eu/eurostat/documents/54431/1966394/LC142-15EN_HBS_2010_Quality_Report_ver2+July+2015.pdf/fc3c8aca-c456-49ed-85e4-757d4342015f

Table 20: Cost per dwelling adjusted by Member States labour costs

Member State	Adjustment factor (MS' labour cost / UK labour cost – category: professional)	Cost per interview (EUR)	Sample size required	Total cost (EUR)
BE	1.3	346	3,459	1,195,000
BG	0.1	27	1,343	36,000
CZ	0.3	82	3,182	262,000
DK	1.2	320	1,697	544,000
DE	1.1	298	37,606	11,209,000
ET	0.2	62	1,619	100,000
IE	1.1	291	2,562	746,000
EL	0.7	184	1,512	278,000
ES	0.7	193	8,743	1,688,000
FR	1.0	274	5,114	1,404,000
IT	1.0	272	8,884	2,420,000
CY	0.8	219	1,910	419,000
LV	0.2	44	1,653	73,000
LT	0.2	44	1,242	55,000
LU	1.3	356	3,068	1,092,000
HU	0.2	60	4,175	250,000
MT	0.4	116	3,157	366,000
NL	0.9	249	1,461	364,000
AT	1.0	269	2,962	796,000
PL	0.3	91	4,022	367,000
PO	0.6	156	30,228	4,708,000
RO	0.2	45	6,328	288,000
SL	0.5	138	2,658	366,000
SK	0.3	69	2,076	143,000
FI	0.9	253	2,532	640,000
SE	1.0	258	2,157	556,000
HR	0.5	138	2,464	340,000
Total Cost				30,704,000

Source: European Commission's calculation

As the housing stock changes slowly, a physical survey of the housing stock does not need to be carried out annually. The survey can be run every two years and produce accurate results[118]. Hence, we estimate that the **total annual cost** of measuring energy poverty using required energy to be approximately EUR **15.35 million**.

The annual cost may increase for those Member States that have to start procurement processes to gather this data. It is likely, however, that the cost of measuring energy poverty using required energy is over-estimated. This is because the SHCS gathers more information than what is explicitly required to measure energy poverty.

The cost of disconnection safeguards – 40 working days minimum notification period

The cost of a minimum notification period can be assessed as the amount of the unpaid energy bills during the period in which disconnection is not possible. This could be either

[118] Based on interview with Scottish Survey manager.

a cost, in case the consumer never pays back the bills, or a delayed income, in case the measure is successfully implemented and the non-paying consumer only delays in paying the bill.

The direct monetary benefit comes in the form of avoided disconnection and reconnection costs to society. To calculate the average amount of time spent on disconnection and reconnection, the cost of disconnection and reconnection was divided by the hourly wage of a technical staff using data from the Standard Cost Model. The average time was equal to 2.4 hours. To calculate the potential savings to society, we assume that the notification reduces the number of disconnections by 10%. We consider 10% to be a conservative assumption. The examples of UK and Belgium show that long pre-disconnection periods contribute, among other factors, to low disconnection numbers. In addition, in many cases disconnections are solved within few days. Notifications are sent to all consumers, many of them, are not necessarily vulnerable or in low-income but have simply forgotten to pay their energy bills.

After the notification, households will be disconnected and acquire a debt with their energy supplier. In many cases, those households will be reconnected again and the debt will be repaid either by the households or the Government. In other cases, a household can be declared in bankruptcy and never repay the debt. For those cases, the unpaid bill during the notification period will be a cost for the supplier. To calculate this cost, we assume[119] a high cost scenario where 30% of households will never repay their debts and a central cost scenario for which 10% households will never repay their debt.

There are no statistics available with the number of households permanently without electricity or gas as a result of non-payment. Anecdotal evidence, gathered through discussions with national regulators, indicate that this number may be small. Given that the majority of European households connected to the electricity or gas grid do receive energy services, it is possible that before or after a household is being disconnected, some kind of process starts by which the affected household or the public sector repay the debt or it is condoned by the supplier.

This is highly likely in Member States with strong social security systems such those who may have to extend their notification like Austria, Germany, Denmark, France, or Sweden and Member States such as Ireland and Poland where pre-payment meters are offered to households as a last resort measures to provide energy and slowly repay the debt. For these Member States, extending the notification period may not result in any added cost. However, to avoid any under-estimation of the cost we have added all the Member States with notification periods lower than 40 days.

The steps taken to calculate the total net costs are the following:

- Calculate the cost of connection and disconnection in each Member State impacted by this measure.

[119] The assumed number of households unable to repay the debt was checked against regulators' experiences.

- Estimate the savings of a longer notification period which equals to the avoided cost of connection and reconnection.
- Calculate the average household energy expenditure for 40 working days in each Member State impacted by this measure.
- Estimate the cost of the measure assuming that 10% (central cost scenario) and 30% (high cost scenario) of households will never repay their debt.
- Calculate the net cost of the policy.

The net cost of unpaid bills for these two scenarios for those Member States with a notification period lower than 40 working days is presented in Table 21.

Table 21: Estimated cost of extending notification period

Member State	Central Cost (10%) in EUR	High Cost (30%) in EUR
AT	148,160	1,027,465
BG*	184,081	624,502
CY	236,164	942,264
CZ*	405,482	1,587,838
DE	627,268	9,340,006
DK	219,079	1,216,659
EE*	-5,018	96,725
FR	1,617,788	6,439,202
IE	35,596	222,339
IT	-570,068	18,342,145
LT	6,046	24,428
LU*	3,194	24,311
MT	11,103	47,098
PL	945,689	4,131,371
PT	2,328,274	9,210,831
SE*	156,570	778,667
SI*	204,133	708,164
SK	109,395	484,050
Total Annual Cost	**6,662,934**	**55,248,063**

*Note: * indicates Member States without available data on disconnections. For these Member States disconnections was proxy by the average number of disconnections.*
Source: European Commission's calculation

Estonia and Italy enjoy a net benefit from extending the notification period i.e. expressed as a negative cost. In these Member States, the savings from avoiding the cost of connection and reconnection during the notification period is higher than the total debt in the central cost scenario where 10% of households do not repay their debt.

The results in Table 21 are nonetheless sensitive to the assumptions used with regard to the number of disconnections avoided and the number of households who will never repay their debt. For instance, if we assume that just 5% of households do not repay their debt, extending the notification period results in an EU net benefit of more than EUR 5 million.

It is also important to note that publically available data on disconnection rates across all Member States is incomplete, despite Member States' obligation to report such data to National Regulatory Authorities. For the purpose of the present analysis, the average number of disconnection was applied to proxy for potential disconnection in those Member States without available data. This assumption may not be adequate for Member States such as Luxembourg or Sweden which may have a significantly lower number of disconnections than the average.

Overall, it is likely that the conservative assumption used in the calculation of the costs led to conservative estimates of the cost which may over-estimate the impact of the measures.

In addition to the above it is important to note that Member States with robust social security schemes are unlikely to face any additional costs as a result of the extension of the disconnection notice period as rapid intervention of social security services typically helps households in those Member States to avoid disconnections.

<u>The cost of disconnection safeguards - prior to disconnection notice, consumers should receive: (i) information on the sources of support and (ii) be offered the possibility to delay payments or restructure their debt.</u>

To calculate the cost of these measures, we collected information on the cost of similar schemes currently operating in Member States and estimate the cost of replicating these schemes in the Member States where debt management or customer engagement activities do not exist.

The steps taken to calculate the total costs are the following:

- Gather information on case studies and calculate the cost per household for debt management and customer engagement.
- Calculate the cost per household in each Member States taking account of different labour costs using information from the Standard Cost Model.
- Multiply the cost per household by the number of households in arrears (high cost scenario) and the number of disconnections (central cost scenario)

Similarly to the cost of extending notification period, it is likely that in some Member States, particularly those with strong social security system, households may never need debt management advice or information on the sources of support.

It might well be that even though Member States such as Denmark, Finland, or the Netherlands do not have official debt management advice or customer engagement activities[120], households in these Member States do receive support prior to disconnection or when facing difficulties to pay their energy bills. That will make these measures superfluous. In those cases, Member States will not face any additional cost. However, to avoid any under-estimation of the costs, the impact assessment includes all the Member States without these services[121].

Using the number of households in arrears as a proxy for the number of disconnections may also over-estimate the costs. First of all, not all households in arrears may be in a position to require support. Arrears may well be for other reasons than financial constraints or difficulties to make ends meet. Secondly, in some Member States, households in arrears may receive support from local authorities or social services which will erase the need for these measures and thus the cost.

[120] *"Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers".* Forthcoming publication. Insight_E

[121] *"Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers".* Forthcoming publication. Insight_E

As a result of these assumptions, we believe the costs presented here are conservative.

The cost of debt management

Step Change is a UK based charity which helps people overcome their debt difficulties[122]. In 2014, the charity served more than 300,000 people at an operating cost of around GBP 140 per beneficiary which equates to around EUR 172[123]. A similar scheme operates in Germany at the local level[124]. The cost of the Germany scheme was on average EUR 167 per households. The estimations are based on the cost from the UK based programme since it is run nationally. Nonetheless, the UK and German program have similar cost per households.

Assuming the same efficiency in other Member States but different labour costs, the cost of replicating Step Change activities in other Member States is shown in Table 22. The same Table also shows the cost of extending the services to all households in arrears with utility bills (as potential households in need of assistance with managing utility bills – high cost scenario) and the cost of providing the service to those households who are actually disconnected[125] – central cost scenario.

When estimating the costs of debt management it is important to note that debt management assistance have positive long-term impacts on households. This means that a substantial share of households benefiting from debt management assistance can be expected to manage their payments more effectively after the initial intervention. Thus, the annual cost of this intervention can be expected to decrease annually reflecting the success rate of the measure.

For instance, from the more of 1,200 households receiving support in Germany, 90% of the beneficiaries felt their future energy needs would be secured and therefore were not in need to reapply to receive assistance. In addition 80% of the disconnection threats were averted which generates savings in the form of avoided disconnection and reconnection costs.

The 90% success rate in the German example may not be easy to replicate in other Member States. As a conservative assumption we assume a success rate of 25%. Hence, the annual cost of the measure will decrease by 25% year-on-year.

It is also important to note that this type of services, despite being of a considerable cost per customer provide an added-value to the energy suppliers. For example, Step Change is partly funded by the energy suppliers as they enjoy the benefits of having an

122 Step Change: http://www.stepchange.org/

123 2014 average exchange rate of GBP 0.806 for one euro.

124 Information on the scheme can be found at: https://www.verbraucherzentrale.nrw/mediabig/238730A.pd and https://www.verbraucherzentrale.nrw/mediabig/237456A.pdf

125 Information on the total number of disconnections was not available for all Member States. For those Member States for which this information was not available, we applied the average disconnection rate.

intermediary that provides support to customer on arrears or in risk of disconnection for non-payment.

The cost of customer engagement

Irish suppliers have established an Energy Engage Code which provides guidelines on the approach suppliers should take with customers in arrears and those with possible disconnection. According to the Code, suppliers should communicate with customers having difficulties in paying their bills and advise them on possible debt management plans. The cost of this option involves communication costs including letter, phone calls and SMS messages. Information on the estimated cost of customer engagement provided by one of the main Irish suppliers is presented below:

- Written communication: EUR 1.5
- Phone calls: EUR 5
- Mobile Text: 8 euro cents

It is likely that this measure may have positive long-term impacts reducing the number of beneficiaries and the cost of the scheme. However, we did not find any evidence of the possible success rate. To avoid any under-estimation of the cost we assume the number of beneficiaries remains constant over time.

This amounts to an estimated cost of customer engagement of around EUR 6.6 per customer. The same approach as per debt management was used to calculate the cost of extending similar schemes to other Member States. We first adjust the cost of customer engagement per customer for each Member State using Eurostat Purchasing Power Parity Index. The cost per customer was multiplied by the total number of households in arrears – high cost scenario and total number of disconnections – central cost scenario.

Table 22: Cost of debt management and customer engagement

Member State	Estimated cost of debt management (EUR)		Member State	Estimated cost of customer engagement (EUR)	
	Central Cost	High cost		Central Cost	High Cost
BG	114,408	6,770,270	BG	21,056	1,245,997
DK	7,665,949	73,559,897	CY	121,107	97,921
EE	65,607	3,882,393	CZ	9,217	545,417
FI	708,564	41,930,412	EE	7,045	416,885
HR	1,016,791	22,934,923	FI	25,786	1,525,929
LT	95,899	5,634,449	GR	900,327	4,138,621
LV	22,088	1,266,903	HR	52,140	1,176,085
PT	33,574,204	91,806,810	HU	410,753	1,139,442
RO	293,008	17,339,207	LT	11,309	664,469
SK	121,024	7,161,768	LV	3,129	179,479
			MT	12,187	100,663
			NL		9,876,748
			SI	116,888	164,857
Total Annual Cost	43,677,542	272,287,031	Total Annual Cost	1,690,944	21,272,514

Note: the number of reported disconnections in the Netherlands was nil. CEER database
Source: European Commission's calculation

<u>The cost of disconnection safeguards - winter moratorium of disconnections for vulnerable consumers.</u>

A winter disconnection moratorium for vulnerable consumers may result in a cost for the energy supplier, consumers or the government, depending on how the measure is financed. The cost of this measure can be estimated as the cost of the unpaid energy bill from non-paying vulnerable consumers during winter. However, the debt per each non-paying household might be recovered at a certain point, therefore not resulting in a cost.

The cost per non-paying household of a possible winter disconnection is reported in Table 23. This was calculated assuming that a household does not pay the energy costs for the full winter, assumed to be four months long which is equal to the average legislated winter length in countries that have disconnection safeguards for the winter. This was calculated using the average energy expenditures for the lowest income quintile.

We also assume that a percentage of vulnerable consumers will not repay their energy bill due to the moratorium. A high and a central cost scenario are presented in the table below. The scenarios assume that 30% (high cost) and 10% (central cost) of the vulnerable households will not repay their energy bills during winter. It can be argued, as it was done previously for the other disconnection safeguards, that these assumptions are likely to over-estimate the cost.

It might be that some Member States such as Austria, Germany or Luxembourg have sufficient tools in place to protect vulnerable households from being disconnected making a moratorium unnecessary. For those Member States, the costs of the moratorium will not be realised. However, as in the other Sections of the impact assessment, we have included all Member States without a winter moratorium for vulnerable consumers.

As previously discussed, anecdotal evidence suggests that the number of households permanently cut-off from electricity and gas services because of non-payment may be significantly lower.

The number of vulnerable consumers was not available for some of the impacted Member States. In these cases, referred in the table below with an asterisk, the number of vulnerable consumers the number of households unable to keep their homes adequately warm was used as a proxy. This is likely to over-estimate the number of vulnerable households, particularly in those Member States with an explicit definition of consumer vulnerability in energy markets. Further information on the definition of consumer vulnerability in energy markets can be found in the evaluation.

It needs to be added that the inability of a vulnerable household to pay its energy bill may also be linked to the type of tariff. It might well be that vulnerable households are not in the most advantageous tariff. In those cases, switching to a more competitive offer reduces energy costs and may avoid disconnection. These interactions were not taken into account in this impact assessment. However, it can be assumed that the preventative measures undertaken prior to disconnection such as customer engagement and debt management may assist vulnerable consumers to reduce their energy cost by switching to a more economic tariff.

Finally, there might be scope for reducing the costs of winter moratorium of disconnections if it is designed taking into account Member States national social services. However, as social policy is a primary competence of Member States, an EU winter moratorium on disconnections may go beyond the limits of subsidiarity (see Section 7.1.6 Subsidiarity).

Table 23: Cost of winter moratorium for vulnerable consumers

Member state	Vulnerable consumers	Electricity		Gas	
		Central cost case (10% disconnect and never pays back) in EUR	High cost case (30% disconnect and never pays back) in EUR	Central cost case (10% disconnect and never pays back) in EUR	High cost case (30% disconnect and never pays back) in EUR
AT*	118,357	2,092,547	6,277,640	733,812	2,201,435
BG*	1,048,035	9,643,610	28,930,829	229,965	689,895
CZ*	267,191	4,559,591	13,678,772	2,807,494	8,422,483
DE*	1,978,803	33,507,728	100,523,184	15,962,343	47,887,029
LU*	1,374	26,642	79,926	20,210	60,630
LV*	215,001	1,743,136	5,229,408	607,682	1,823,046
MT	24,416	242,927	728,782	36,852	110,557
PT	61,129	941,387	2,824,160	707,059	2,121,176
SK*	117,990	1,172,983	3,518,950	1,333,957	4,001,872
Total Annual Cost		53,930,551	161,791,651	22,439,374	67,318,123

Note: Vulnerable consumers for AT, BG, CZ, DE, LU, LV and SK set as the number of households feeling unable to keep warm during winter. It was not possible to calculate the cost for Croatia due to lack of data on household energy expenditure

Source: European Commission's calculation

Summary Table

The annual cost and the total net present cost for the period 2020 and 2030 of the policy options presented in the impact assessment are summarised in the Table below.

Table 24: Total Cost

	Annual cost in EUR	Net present cost for the period 2020 – 2030 in EUR
BAU: sharing of good practices.	0	0
Option 0+: sharing of good practices and increasing the efforts to correctly implement the legislation.	100,000	911,090
Policy Option 1: Setting an EU framework to monitor energy poverty		
Central cost scenario	407,375 (first year) 228,621 (following years)	2,261,696
Policy Option 2: Setting a uniform EU framework to monitor energy poverty, preventative measures to avoid disconnections and disconnection winter moratorium for vulnerable consumers.		
Central cost scenario	159,105,345	1,194,481,728
High cost scenario	587,348,869	3,820,183,393

Source: European Commission's calculation

Quantifying the Benefits

In this Section we describe the benefits derived from implementing the policies.

Overall benefits

Tackling energy poverty can have positive effects on individual's health and well-being, savings for the health sector, as well as provide economy-wide gains on productivity levels. Although it is difficult to quantify the specific impact of the policies presented in this impact assessment towards these overall benefits, it is likely that applying these policies will contribute to reap these benefits.

For instance, it is likely that on individual's health, there have been various studies linking cold homes with respiratory illnesses and excessive winter mortality. The World Health Organisation estimated that 30% of Excess Winter Deaths (EWD) can be directly related to cold homes[126]. The 2009 Annual Report of the Chief Medical Officers[127] estimated that for every £1 spent on ensuring homes are kept warm, the public health sector saves £0.42.

A recent study concluded that home environment is key to ensure citizens are healthy and productive[128]. Remaining connected to an energy supply better enables households to maintain healthy homes in terms of indoor temperature and humidity levels. Lack of energy supply has been linked to an increase of respiratory illnesses, circulatory diseases, mental health and allergies, which, left unchecked, lead to absence from work and loss of productivity estimated to total 9.8 billion EURO annually in Europe[129][130][131]. Policies proposes in the revision of the EED and the EPBD which contribute to better energy efficiency in the domestic sector will also contribute to realise benefits of better health and productivity.

The UK Healthy Homes Barometer 2016 estimates that minor illnesses, such as coughs, colds, flus and illnesses can be attributed to 27 million lost working days, which affect morale and productivity. The direct cost to the economy in the UK due to these absences is estimated at £1.8 billion in 2013.

Ensuring energy provision can also have a positive impact on educational attainment, lower missed school days and life chances for children[132].

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126 "*Indoor cold and mortality. In Environmental Burden of Disease Associated with Inadequate Housing"*, (Bonn: World Health Organisation (Regional office for Europe)). (2011). Rudge, J.

127 2009 Annual Report of the Chief Medical Officer (London: Department of Health). 2010. Donaldson, L.

128 "*Healthy Homes Barometer"*. (2016). Wegener and Fedkenheuer,

129 *"Towards an identification of European indoor environments' impact on health and performance - homes and schools"*. (2014). Grün & Urlaub,

130 *"The Health Impacts of Cold Homes and Fuel Poverty"* (London: Friends of the Earth). (2011). Marmot Review Team.

131 *"Estimating the health impacts of Northern Ireland's Warm Homes Scheme"* 2000-2008. (2008). Liddell.

132 *Evaluating the co-benefits of low-income energy-efficiency programmes*. 2013. Heffner & Campbell.

Identifying energy poverty will also assist Member States in assessing the level of energy poverty. Such identification will support Member States to better target public policies to those households in need of assistance. In addition, disconnection safeguards will further help Member States to reduce the number of disconnections, benefiting in particular low-income households who are more likely to face energy poverty. With such measures in place, Member States may feel more confident to phase out regulated prices.

The removal of regulated prices which will bring efficiency improvements, resulting on:

- more competition in the energy markets with positive impacts on consumer and innovation;
- the removal of market distortions which alter the allocation of resources.
- additional citizen's satisfaction due to the positive impacts of competition on innovation in the form of enhanced service provision and quality;
- a positive impact on the internal energy market. Companies wishing to engage in cross-border trade will not be discouraged by regulated prices, which prevent competition when set below cost,; and
- improved public finances since regulated prices are an ineffective measure of protection as they are applied to all households, including those who can afford to pay a higher price. Phasing out regulated prices will unlock resources which can be used for targeted protection.

Better information on the level of energy poverty and measures to reduce the number of disconnections will have a positive impact on consumer protection and the health and well-being of European citizens. Art. 38 of the Charter of Fundamental Rights of the EU requires EU policies to ensure a high level of consumer protection. The Treaty establishes that *'consumer protection requirements shall be taken into account in defining and implementing other Union policies and activities'* (TFEU, art. 12), and that '*... the Union shall contribute to protecting the health, safety and economic interests of consumers, as well as to promoting their right to information, education and to organise themselves in order to safeguard their interests*.' (TFEU, Art. 169)

Policy Option 1 – assessing the benefits

<u>The benefits of a generic description of the term energy poverty in the legislation</u>

Three main benefits have been identified as a result of a shared understanding of energy poverty across the EU: recognition, clarification and policy synergy[133].

In terms of recognition, an EU description of energy poverty may help Member States to identify the problem. This is relevant as the majority of Member States have not defined the phenomenon of energy poverty despite the evidence which suggest that household across Europe are struggling to access adequate energy services[134],

As for clarification, a major regulatory impediment to addressing energy poverty is the unclear understanding of the term. This is particularly relevant as in many cases the term

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133 "*Fuel poverty in the European Union: a concept in need of definition?"* 2016. Thomson et al.
134 *"Quantifying the prevalence of fuel poverty across the European Union"*. (2013). Thomson and Snell.

energy poverty is mixed or used interchangeably with the broader term of consumer vulnerability or general poverty[135]. Adopting a generic description of energy poverty would help to resolve the terminological confusion that presently exists, and may pave the way for more detailed national definitions. Above all a generic common understanding of energy poverty in the EU, which focuses on the drivers of energy poverty, is a necessary prerequisite towards achieving reliable and comparable data on the current and future evolution of the nature and scale of the issue.

In terms of policy synergy, there is potential for achieving synergies at the EU and Member State level. Having a shared concept could also assist Member State cooperation and knowledge exchange in this area.

<u>The benefits of measuring energy poverty by referring to household income and household energy expenditure</u>

Measuring energy poverty will assist Member States to assess whether energy poverty is getting better or worse over time. It will also help Member States to identify the people affected so that they can be targeted by appropriate interventions. Hence, measuring energy poverty will help policy makers to assess the impact of their policies[136].

In summary, measuring energy poverty will enable Member States to:

- measure the level of energy poverty at a particular moment of time
- identify trends and changes on the levels of energy poverty,
- understand the extent, depth and persistence of the problem,
- identify the kinds of people affected; and
- support policy design and delivery to tackle the problem

These offer the necessary clarity to the term energy poverty, as well as, the transparency with regards to the number of household in energy poverty while respecting the principles of subsidiarity.

Option 2– assessing the benefits

<u>The benefits of a specific EU definition of energy poverty</u>

A specific, harmonised EU definition of energy poverty such as the one explained previously will bring benefits similar to those associated with a general definition of energy poverty. In addition, being a more specific definition, we expect the benefits in relation to clarification to be higher.

However, here it is important to remember the risks that a specific definition of energy poverty at the EU level may bring in terms of currently limited comparable evidence, comparability and relevance, and path dependency[137] .

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[135] "*Working Paper on Energy Poverty*".(2016). Vulnerable Consumer Working Group.
[136] *Fuel Poverty: The problem and its measurement*. (2001). John Hills. Available at: http://sticerd.lse.ac.uk/dps/case/cr/CASEreport69.pdf
[137] *"Fuel poverty in the European Union: a concept in need of definition? "* (2016). Thomson et al.

As discussed before, a specific EU definition of energy poverty may be in conflict with the diversity of contexts at the Member States in terms of climate conditions, socioeconomic factors or energy markets. If the definition were to be inadequate for a Member State, it would take considerable amount of time to change the EU legislation and amend this situation.

The benefits of Member to measure energy poverty using required energy

Measuring an adequate level of energy services is the main advantage of using required rather than actual expenditure. This is the approach taken in the UK and it is regarded as most appropriate by several experts[138]. It requires, nonetheless, agreeing on what is adequate. In some cases, the term adequate refers to a specific heating regime[139].

Having defined what is adequate, the required energy approach calculates the amount of energy needed to meet that heating regime. Energy poverty is later computed comparing the required energy expenditure against household income. Hence, required energy expenditure solves the main weakness of the actual expenditure approach. When using actual expenditure, we are not able to distinguish between those households that do not consume sufficient energy because of financial constraints from those that do not need much energy to meet their energy needs because they live in a high energy efficient dwelling.

The benefits of disconnection safeguards - minimum notification period

Longer disconnection periods will provide customers with additional time to engage with suppliers and/or seek help. There is a direct monetary benefit in the form of avoided disconnections and reconnection costs. In addition to these benefits, any avoided disconnection stemming from this measure will bring benefits such as health improvements and cross-department savings in social and health budgets, and improvements in equality.

Suppliers will also benefit from lower disconnection rates as they will retain such customers, thereby avoiding lost income, allowing the customer to pay back arrears, and avoiding some of the costs related to new customer acquisition.

The benefits of disconnection safeguards - prior to disconnection notice, consumers should receive: (i) information on the sources of support and (ii) be offered the possibility to delay payments or restructure their debt.

Providing additional information to consumers and the possibility to delay payments or restructure their debt may result in a number of disconnections being averted. Hence, the benefits are similar as in the case of extended notification period In addition, households will be better informed, and can improve their energy management and potentially avoid future debt. As described in the case of minimum notification period, suppliers will also

[138] *"Selecting Indicators to Measure Energy Poverty"*. (2016). Trinomics.

[139] For instance in the case of Scotland, the current definition of fuel poverty makes reference to a heating regime for standard occupants between 21°C and 18°C for 9 hours during weekdays and 16 hours else and for any occupant aged 60 or more or long-term sick and disabled between 23°C and 18°C 16 hours per day. Source: http://www.gov.scot/resource/0039/00398798.pdf

benefit from lower disconnections. Investment in consumer engagement and debt management services will support a number of jobs in services such as debt counselling.

The benefits of winter moratorium of disconnections for vulnerable consumers.

Similar to the other measures which reduce disconnections, a winter moratorium will bring benefits in the form of health benefits to vulnerable consumers, cross-departmental savings in social and health budgets, and avoided disconnection and reconnection costs.

Sensitivity analysis

This impact assessment suffers from important shortcomings to quantify the benefits. The policy options bring multiple benefits in terms of better public policy with regard to energy poverty, improvements in individuals' well-being and public sector saving from fewer disconnections. However, we were not able to quantify the value of these benefits from market prices.

Sensitivity analysis allows us to calculate the amount of benefits that would be necessary to justify the costs from these policies.

One of the key benefits of the options presented stem from improvements in individual health which can be particularly effective at addressing Excess Winter Deaths (EWD). EWD refers to deaths which would not have occurred if dwellings had been properly heated. The cost to society of EWD can be estimated as forgone GDP i.e. each excess winter death translates in forgone monetary value approximated by GDP per capita. This is a rather crude measure with some disadvantages (e.g. different values for different countries) but it can be interpreted as an estimation of the loss to society.

To perform the sensitivity analysis, the following steps are taken:

- Aggregate the cost of policy Option 1 and 2 for the high and central cost scenario.
- Multiply the number of EWD[140] by the GDP per capital[141]
- Calculate the reduction in EWD that equals the cost of the policies.

The results of the calculation are presented below.

Table 25: Sensitivity analysis

	Benefits from reduction in Excess Winter Deaths equal to the cost of the policies
Policy Option 1: Setting an EU framework to monitor energy poverty	
Policy Option 1 – first year	0.004%
Policy Option 1 – following years	0.002%
Policy Option 2: Setting an EU uniform framework to monitor energy poverty and reduce disconnections for vulnerable	

140 The number of EWD is calculated following an approach similar to Johnson and Griffinths (2003). The number of deaths is equal to the deaths between the months of December and March minus the average number of deaths for other months. Data source: Eurostat. Mortality Statistics.

141 Eurostat. GDP per capital in euros at current prices.

consumers.	
Policy Option 2 – central cost scenario	1.5%
Policy Option 2 – high cost scenario	5.6%

Source: European Commission's calculation. Note: Policy Option 1 and 2 include the measures described in option 0+.

The Table shows that a minimal reduction in EWD is sufficient to justify the cost arising from policy Option 1. On the other hand, a reduction of 1.5% and 5.6% is necessary for the cost of policy Option 2 to be equal to possible benefits. The differences between the low and high cost scenario are explained by the assumptions used to calculate the cost, and in particular, to the number of households that after being disconnected or because of the moratorium will never repay their debt.

Box 1: Impacts on different groups of consumers

The benefits of the measures contained in the preferred option (Option 1), described in detail in the preceding pages, accrue overwhelmingly to energy poor households. Depending on how individual Member States choose to finance their new obligations to measure energy poverty levels (costs outlined in detail in Tables 15 to 17), the marginally increased burdens resulting from the implementation of these measures are socialized amongst other ratepayers or taxpayers. The measures can therefore be considered progressive in nature i.e. they tend to redistribute surplus from relatively high-income ratepayers/taxpayers to increase the welfare of lower-income ratepayers

7.1.6. *Subsidiarity*

In this Section we assess the options presented in the impact assessment against the subsidiarity principle as stated in Article 5 of the Treaty of the EU.

The subsidiarity principle is upheld because the objectives of the policy options, which have been defined to address the shortcoming of the current legislation as identified in the evaluation, cannot be achieved sufficiently by Member States.

The evaluation of the current provision of the Electricity and Gas Directive defined energy poverty as a subset of consumer vulnerability. This categorisation leads to a simplistic expectation that a single set of policy measures from Member States would automatically address both problems simultaneously. However, evidence suggests that energy poverty has been rising over the years, despite the protection available for vulnerable consumers. In this context, Member States have been reluctant to phase out regulated prices, pointing towards the protection of vulnerable and energy poor households as one of the main reasons. As a consequence, national regulation has had negative spill-over effects, weakening the internal energy market.

The measures proposed in Option 1 build upon the existing provisions on energy poverty in the Electricity and Gas Directive. They offer the necessary clarity to the term energy poverty, as well as, the transparency with regards to the number of household in energy poverty. Since currently available data can be used to measure energy poverty, the administrative costs are limited. Likewise, the actions proposed do not condition Member States primary competence on social policy, hence, respecting the principle of subsidiary.

In addition, the protection of vulnerable and energy poor consumers has been quoted as one of the reasons for maintaining regulated prices. This type of intervention, particularly when prices are regulated below costs, has negative implications on the functioning of the internal energy market. Article 114 and 194 pf the Treaty pf the Functioning of the European Union states that in order to achieve the objectives in Article 26, the EU legislators *shall adopt the measures for the approximation of the provisions laid down by* *law, regulation or administrative action in Member States which have as their object the establishment and functioning of the internal market*. Article 194 states that the Union *policy shall aim to ensure the functioning of the energy market*.

It can be argued that Article 169 on Consumer Protection provides further justification for action at the EU level. The options described in this IA include disconnection safeguards either as preventative measures prior to disconnection or as a prohibition of disconnection for vulnerable consumers.

The options presented in this Annex bring a double dividend: on the one hand they contribute to the protection of consumers – as explained in the introduction there is a link between energy poverty and excess winter deaths – and on the other hand, these measures support the completion of the internal energy market.

It needs to be noted that, as we explained in Option 2, Member States may be better suited to design schemes to protect households from disconnection in order to ensure that synergies between national social services and disconnection safeguards are achieved.

In addition, a prohibition on disconnections for vulnerable consumers may restrict the principle of freedom of contract, in particular for the ten Member States that do not have such a measure in place. However, action at EU level may be the most effective way to ensure a common level of protection for vulnerable consumers. Furthermore, in terms of proportionality, Member States should carefully specify the group of vulnerable consumers who cannot be disconnected to avoid going beyond what is necessary to achieve the consumer protection objective.

7.1.7. Stakeholders' Opinions

The options described in this impact assessment have benefited from the continued dialogue between the European Commission services and civil society through the Vulnerable Consumer Working Group (VCWG).

The VCWG was reconvened after the 2015 Citizens' Energy Forum. The group has met five times since then:

- 3 June 2015
- 21 October 2015
- 9 December 2015
- 26 January 2016
- 24 May 2016

The VCWG meetings are attended by key stakeholders from industry, consumer associations, academics, regulators and representatives of Member States. A full list of the members of the group who have attended at least one of the last five meetings is provided below:

Table 26: Members of the Vulnerable Consumer Working Group

Organisation	Member State
Ministry of Economics	Latvia
Ministry of Economy	Poland
Ministry of Employment and the Economy, Energy Department	Finland
Ministry of National Development	Hungary
Bulgarian Permanent Representation to the EU	Bulgaria
Hungarian Permanent Representation to the EU	Hungary
Czech Permanent Representation to the EU	Czech Republic
FPS Economy - DG Energy	Belgium
ERO - Energy Regulatory Office of the Czech Republic	Czech Republic
E-control Austrian Energy Regulator	Austria
OFGEM	United Kingdom
NEON	European Organisation
Citizens advice	United Kingdom
Danish Consumer Council	Denmark
DECO	Portugal
The Swedish Consumer Energy Markets Bureau	Sweden
RWADE	Belgium
University of Leicester	United Kingdom
University of Stuttgart	Germany
European Disability Forum	European Organisation
Fondazione Consumo Sostenibile	Italy
GEODE	European Organisation
HISPACOOP	Spain
Housing Europe	Belgium
International Union of Tenants	European Organisation
EURELECTRIC	European Organisation
EUROGAS	European Organisation
ADEME	France
AEEGSI	Italy
AISFOR	Italy
CEDEC	European Organisation
DGEC	France
EAPN	European organisation
EFIEES	European Organisation
ENGIE	France
FdSS	France

In the meetings of the VCWG[142], the group discussed the topic of energy poverty. These discussions were captured in the Working Paper on Energy Poverty[143]. The group conclusions were as follows *(emphasis added)*:

- Measuring energy poverty is important to understand the depth of the problem and also assess the impact of the policies which have been put in place to tackle

[142] The minutes, agenda and presentations of the meetings can be found online at: https://ec.europa.eu/energy/en/events/citizens-energy-forum-london

[143] VCWG (2016) Working Paper on Energy Poverty. Available at: https://ec.europa.eu/energy/sites/ener/files/documents/Working%20Paper%20on%20Energy%20Poverty.pdf

it. Metrics which account for the relationship between household income and household energy needs or expenditure capture well the problem of affordability.

- Better information on housing stock, which can be efficiently gathered as part of the regular Household Budget Survey, will help Member States to measure energy poverty and design energy efficiency policies which benefit the energy poor.
- Tackling energy poverty requires a combination of policies, dealing with the causes and the symptoms of energy poverty. Good examples include targeted short-term (financial support) and long-term measures (energy efficiency) in addition to consumer protection and reasonable safeguards against disconnections.
- A common understanding of the concept of energy poverty will help Member States, civil society and industry to start a dialogue about the depth of energy poverty and how to tackle it. The VCWG considers that a common understanding of energy poverty in the form of a generic definition represents a positive step forwards to tackle the problem of energy poverty. Such a definition should be simple, focus on the problem of affordability, and allow sufficient flexibility to be relevant across Member States. The VCWG proposes that such a definition can refer to elements such as low-income; inability to afford; and adequate domestic energy services

The options described in this impact assessment draws from the conclusions of this paper. In particular, key elements of Option 1 are supported by the VCWG Working Paper on Energy Poverty.

Sub-Annex 1

Table 27: Energy poverty definitions

Member State	Definition
France	Energy Poverty: A person who encounters in his/her accommodation particular difficulties to have enough energy supply to satisfy his/her elementary needs, this being due to the inadequacy of resources or housing conditions.
Ireland	Energy poverty is a situation whereby a household is unable to attain an acceptable level of energy services (including heating, lighting, etc.) in the home due to an inability to meet these requirements at an affordable cost.
Cyprus	Energy poverty may relate to the situation of customers who may be in a difficult position because of their low income as indicated by their tax statements in conjunction with their professional status, marital status and specific health conditions and therefore, are unable to respond to the costs for the reasonable needs of the supply of electricity, as these costs represent a significant proportion of their disposable income.
Slovakia	Energy poverty under the law No. 250/2012 Coll. Of Laws is a status when average monthly expenditures of household on consumption of electricity, gas, heating and hot water production represent a substantial share of average monthly income of the household"
England	Energy poverty: A household i) income is below the poverty line (taking into account energy costs); and ii) their energy costs are higher than is typical for their household type.
Scotland	Fuel poverty: A household, in order to maintain a satisfactory heating regime, it would be required to spend more than 10% of its income (including Housing Benefit or Income Support for Mortgage Interest) on all household fuel use.
Wales	Fuel poverty is defined as having to spend more than 10% of income (including housing benefit) on all household fuel use to maintain a satisfactory heating regime. Where expenditure on all household fuel exceeds 20% of income, households are defined as being in severe fuel poverty.
Northern Ireland	A household is in fuel poverty if, in order to maintain an acceptable level of temperature throughout the home, the occupants would have to spend more than 10% of their income on all household fuel use.

Source: Insight_E 2015

7.2. Phasing out regulated prices

7.2.1. *Summary table*

Objective: Removing market distortions by achieving the phase-out of supply price regulation for all customers[144].			
Option: 0	**Option 1**	**Option 2a**	**Option 2b**
Making use of existing *acquis* to continue bilateral consultations and enforcement actions to restrict price regulation to proportionate situations justified by general economic interest, accompanied by EU guidance on the interpretation of the current acquis.	Requiring Member States to progressively phase out price regulation for households by a deadline specified in new EU legislation, starting with prices below costs, while allowing transitional, targeted price regulation for vulnerable customers (e. g. in the form of social tariffs).	Requiring Member States to progressively phase out price regulation, starting with prices below costs, for households above a certain consumption threshold to be defined in new EU legislation or by Member States.	Requiring Member States to progressively phase out below cost price regulation for households by a deadline specified in new EU legislation.
Pros: - Allows a case-by-case assessment of the proportionality of price regulation, taking into account social and economic particularities in Member States	Pros: - Removes the distortive effect of price regulation after the target date. - Ensures regulatory predictability and transparency for supply activities across the EU.	Pros: - Limits the distortive effect of price regulation. - Would reduce the scope of price regulation therefore limiting its distortive impact on the market.	Pros: - Limits the distortive effect of price regulation and tackles tariff deficits where existent.
Cons: - Leads to different national regimes following case-by-case assessments. This would maintain a fragmented regulatory framework across the EU which translates into administrative costs for entering new markets.	Cons: - Difficult to take into account social and economic particularities in Member States in setting up a common deadline for price deregulation.	Cons: - Difficult to take into account social and economic particularities in Member States in defining a common consumption threshold above which prices should be deregulated..	Cons: - Defining cost coverage at EU level is economically and legally challenging. - Implementation implies considerable regulatory and administrative impact. - Price regulation even if above cost risks holding back investments in product innovation and service quality.
Most suitable option(s): Option 1 - Setting an end date for all price intervention would ensure the complete removal of market distortions related to end-user price regulation and help create a level playing field for supply activities across the EU while allowing targeted protection for vulnerable customers and/or energy poor.			

[144] For the purpose of this annex of the impact assessment, households or household customers shall include customers in a comparable situation (e. g. SMEs, hospitals etc.)

7.2.2. *Description of the baseline*

A regulated supply price is considered as a price subject to regulation or control by public authorities (e.g. governments, NRAs), as opposed to being determined exclusively by supply and demand. This definition includes many different forms of price regulation, such as setting or approving prices, standardisation of prices or combinations thereof.

The existing *acquis* only allows price regulation if strict conditions are met.

Regulated prices are unlawful under current Gas and Electricity Directives as interpreted by the Court of Justice, unless they meet specific conditions. Accordingly, the Court of Justice has ruled[145] that supply prices must be determined solely by supply and demand as opposed to State intervention as from 1 July 2007. The Court based its interpretation on the provision[146] stating that Member States must ensure that all customers are free to buy electricity/natural gas from the supplier of their choice as from 1 July 2007 (Article 33 of the Electricity Directive and Article 37 of the Gas Directive interpreted in light of the very purpose and the general scheme of the directive, which is designed progressively to achieve a total liberalisation of the market in the context of which, in particular, all suppliers may freely deliver their products to all consumers).

Article 3(1) of Gas and Electricity Directives requires Member States to ensure, on the basis of their institutional organisation and with due regard to the principle of subsidiarity, that natural electricity/gas undertakings are operated in accordance with the principles of that directive with a view to achieving, inter alia, a competitive market.

However, Gas and Electricity Directives are also designed to ensure that, in the context of that liberalisation, high standards of public service are maintained and the final consumer is protected.

In order to meet those latter objectives, Article 3(1) of Gas and Electricity Directives states that it applies without prejudice to Article 3(2), which expressly permits Member States to impose public service obligations on undertakings operating in the electricity and gas sectors, which may in particular concern the price of supply.

In this context the conditions allowing price regulation in the form of public service obligation imposed on undertakings are to i) be adopted in the general economic interest, ii) be clearly defined, transparent, non-discriminatory and verifiable, guarantee equality of access for EU companies to national customers and iii) meet a requirement for proportionality (which refers in particular to limitation in time and as regards the scope of beneficiaries).

[145] Case C-265/08, Federutility and others v Autorità per l'energia elettrica e il gas

[146] The Court judgement was based on Article 23(1)(c) of Directive 2003/55 of the Second Energy Package which provides that Member States must ensure that all customers are free to buy natural gas from the supplier of their choice as from 1 July 2007; however a similar provision is contained in the Second Package Electricity Directive and the relevant provisions has remained unchanged in the Third Package Directives.

Price regulation for *non-households* has been systematically challenged via infringements while price regulation for *households* has not been yet subject to infringement procedures. Deregulating household prices may be politically unpopular in Member States where regulation is justified by social policy objectives and/or lack of competition.

This policy choice has meant addressing through infringements the more important market distortion created by the regulation of prices for larger and potentially most active consumers who use most of the energy sold on the European market (more than 70% of total electricity consumption and close to 60% of the total gas consumption)[147]. In addition, the Commission has opted initially for an informal approach via bilateral consultations with Member States to discuss reasonable and sustainable alternatives to price regulation and accompanying support for vulnerable consumers. However, infringement actions against price regulation for households are not excluded in the follow-up to informal consultations.

Electricity and gas price regulation refers to the ‘energy’ component of the end-user price, excluding costs of transport/distribution, taxes, other levies and VAT. This component is the element which should be determined by market demand and supply in a fully liberalised energy market. By contrast, the other elements that influence the end-use electricity price are subject to other regulation and legislation including network regulation, taxes and levies/support schemes for energy efficiency and renewable energy sources.

7.2.3. *Deficiencies of the current legislation*

Despite the current acquis, some form of price regulation exists in 17 Member States, as shown in the table below.

This is problematic because evidence presented in Section 5 of the present Annex demonstrates that regulation of electricity and gas prices limits customer choice, reduces customer satisfaction and restricts competition. This is particularly true for markets where supply prices are set below costs (i.e. without taking into consideration wholesale market prices and other supply costs).

Artificially low regulated prices (even without pushing them below costs) limit market entry and innovation, prompt customers to disengage from the switching process and consequently hinder competition in retail markets. In addition, they may increase investor uncertainty and impact the long-term security of supply.

Furthermore, regulated prices (even when set above costs) can act as a pricing focal point which competing suppliers are able to cluster around and – at least in markets featuring strong customer inertia – can also considerably dilute competition.

[147] In 2014, non-residential customers consumed 1.921.153 out of the total 2.706.310 Gigawatt-hour electricity consumption and 1.506.185 Gigawatt-hour out of the total 2.578.779 Gigawatt-hour of gas consumption – Eurostat data, 2014.

As shown in the Evaluation of the EU's regulatory framework for electricity market design and consumer protection in the fields of electricity and gas, market-based energy prices that are able to take into account the rapid changes of demand and response and cross-border trade are even more crucial than in 2009. The evaluation concludes that progress towards lifting regulated prices blocking competition and consumers' choice should continue (Evaluation Section 7.1.1).

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Phasing out regulated prices

Table 1: Energy price regulation in EU Member States – February 2016[148]

Member State	Electricity	Gas
Austria		
Belgium		
Bulgaria	**X**	**X**
Croatia	**X**	**X**
Cyprus[i]	**X**	
Czech Republic		
Denmark[ii]	**X**	**X**
Estonia		
Finland		
France	**X**	**X**
Germany		
UK (Great Britain)		
UK (Northern Ireland)	**X**	**X**
Greece[iii]		**X**
Hungary	**X**	**X**
Ireland		
Italy[iv]	**X**	**X**
Latvia[v]		**X**
Lithuania[vi]	**X**	**X**
Luxembourg		
Malta[vii]	**X**	
Netherlands		
Poland[viii]	**X**	**X**
Portugal[ix]	**X**	**X**
Romania[x]	**X**	**X**
Slovakia	**X**	**X**
Slovenia		
Spain[xi]	**X**	**X**
Sweden		

Source: European Commission Data.

[i] Price regulation economically justified due to natural monopoly.

[ii] **Denmark** is implementing measures aimed at progressively removing regulated prices. This follows from changes in the energy law introduced in January 2013.

[iii] Discussions with **Greece** on the phase-out of regulated prices are conducted as part of the Economic Adjustment Programme and lead to the phase-out of electricity regulated prices for households and small enterprises as of 30 June 2013. The only exceptions are end-user prices for vulnerable customers. As regards gas, a major reform of the Greek gas retail market is envisaged that seeks to abolish the regional monopolies of the EPAs for gas supply and to progressively extend eligibility to all retail customers.

[iv] **Italy** has introduced since 2013 market based reference prices for small customers including SMEs that according to the Italian NRA should be considered de facto non-regulated.

[v] **Latvia** has removed regulated prices for *electricity* for households other than vulnerable in January 2015. As a first step towards price deregulation, a revised Energy Law, adopted on 18 September 2014, introduced a category of vulnerable customers (underprivileged social groups and families with 3 or more children) and set a fixed price for electricity for these customers. Regarding *gas*, the liberalization is expected to be completed by 2017, subject to interconnections projects being realized in order to make the transition from isolated market to an interconnected one.

[vi] **Lithuania** has removed *electricity* regulated prices in the beginning of 2015.

[vii] **Malta** regulates electricity prices for all customer segments. However, it has extensive exemptions notably from market opening and customer eligibility provisions of the Third package.

[viii] Discussions with **Poland** are ongoing regarding draft measures communicated to Commission's services implementing the judgement delivered on 10 September 2015 concerning gas price regulation (*36/14 Commission v. Poland*). The draft measures foresee deregulation of gas prices for households by 2023.

[148] Based on current state of play of the conformity checks.

[ix] **Portugal** has agreed a roadmap for phasing out regulated prices as a result of the infringement proceedings initiated by the Commission. In August 2012, the government announced the complete elimination of regulated tariffs with a transitory tariff in place for three years.
[x] **Romania** has agreed an electricity and gas price deregulation calendar as part of the Economic Adjustment Programme.
[ix] In **Spain**, on 27 December 2013, the new Electricity Act modified the last resort tariff for electricity and introduced the PVCP (Precio Voluntario Pequeño Consumidor or Voluntary price for small customers) for electricity households. The energy component of this price reflects the spot market during the period, only the profit margin of the suppliers being regulated.

7.2.4. *Presentation of the options*

Option 0: Making use of existing acquis to continue bilateral consultations and enforcement actions to restrict price regulation to proportionate situations justified by manifest public interest

This option consists in a new round of bilateral meetings with the Member States as regards households, relying on the existing acquis. Due to the political sensitivity attached to price regulation for households, but also taking into account that national price regulation regimes are characterised by a variety of rules and justifications thereof, voluntary collaboration between Member States based on assistance by the Commission services has not been considered as an adequate tool for achieving price deregulation, a bilateral approach being preferred. Bilateral meetings can be followed by EU Pilots and infringement procedures to restrict price regulation to time-limited situations justified by the public interest.

In this context, the Commission services will:

- offer Member States assistance on practical implementation of deregulation including on accompanying good practice in protecting the energy poor through social policy;
- monitor Member States' adherence to adopted phase-out roadmaps and the implementation of the principle of cost-reflectiveness of their regulated prices; and
- initiate enforcement where Member States refuse to phase-out regulated prices on a voluntary basis.

While enforcement action under this option may be effective, as repeatedly backed by favourable judgements of the European Court of Justice, infringement actions by the Commission against price regulation for households remain politically sensitive.

Option 1: Requiring Member States to progressively phase out price regulation for households by a deadline specified in new EU legislation, starting with prices below costs, while allowing transitional, targeted price regulation for vulnerable customers (e. g. in the form of social tariffs).

The legislative measures would include:

- introducing binding deadlines (e. g. 3-4 years from the entry into force of the legislation) in the Electricity and Gas Directives for price-setting for households to be free of regulatory intervention and instead subject only to supply and demand.

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- allowing regulated prices (e. g. in the form of social tariffs) targeted at specific groups of vulnerable customers, notably the energy poor. This would also contribute to ensuring universal access to affordable energy services as required under UN-backed Sustainability Development goals.

These measures would be accompanied by:

- bilateral consultations, as appropriate, to support Member States in defining and implementing the roadmaps and in identifying vulnerable groups for special protection.
- technical advice, guidance and sharing of good practices on energy efficiency, alternative financial support measures (e. g. energy cheques) or income support through the welfare system to complement or progressively substitute the need for social tariffs.

This option might accelerate liberalization processes in Member States by establishing a clear target date for price deregulation while allowing regulated prices as targeted, transitional support to vulnerable customers. However, it would not fully take into account social and economic particularities in Member States in setting up a common deadline for price deregulation.

Option 2a: Requiring Member States to progressively phase out price regulation, starting with prices below costs, for households below a certain consumption threshold to be defined in new EU legislation or by Member States, with support from Commission services.

If the consumption threshold is defined below current levels used by Member States to apply price regulation, this option would reduce the scope of price regulation therefore limiting its impact on the market.

The main challenge of this option concerns the calculation of the right thresholds. Allowing regulated prices up to certain rather low energy consumption thresholds may miss out some poorer customers who may consume rather more energy per household, as they may spend more time in their homes (due to unemployment, invalidity, home work), live in poorly insulated dwellings or require to be connected to medical equipment. As a consequence they may exceed the defined thresholds. On the other hand and contrary to the desired effect, ordinary customers of sufficient wealth but low consumption e.g. due to a lifestyle with a relatively limited use of appliances may profit from such thresholds. The same might apply to secondary homes inhabited only temporarily by wealthier customers.

Maintaining regulated prices for large parts of consumption through high thresholds prevents the development of market-based demand response and other flexibility options, as price-based incentives cannot be created through price regulation schemes as effectively as by the market. This option could thus limit the achievement of the full effects of the Market Design initiative, particularly its elements aimed at end-customers.

Option 2b: Requiring Member States to phase out below cost price regulation by a deadline specified in new EU legislation.

While this option would limit the distortive effect of price regulation and tackle tariff deficits, maintaining regulated prices, even if above cost, would prevent the development of market-based demand response and other flexibility options, as price-based incentives

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cannot be created through price regulation schemes as effectively as by the market. Moreover, price regulation that does not allow charging more than current costs risks holding back investments in product innovation and service quality.

The main challenge of this option would be to define cost coverage methodologies for price regulation at EU level. It is legally challenging as the current EU *acquis* establishes as a general rule that prices should be set by market forces; moreover, this option could produce weaker effects than current EU *acquis* as it would limit the requirement of proportionality to be met by price regulation only to the cost coverage aspect (not taking into account the limitation in time, in the scope of beneficiaries or the necessity test). It is also economically challenging due to opaque cost structures of the companies. Moreover, ensuring cost-reflectiveness by regulation would imply considerable regulatory and administrative impact.

7.2.5. *Comparison of the options*

Comparison of performance of energy markets with and without price regulation

The objective of this Section is to assess the performance of energy markets where prices are established by a governmental authority (they are regulated) with that of markets where prices are set in market conditions, by supply and demand. The assessment is made based on the level of competition within each group of markets, according to the conventional structure-conduct-performance framework, which explores a range of retail market indicators such as market structure and concentration, consumer switching activity and consumer experience.

In order to assess the performance of markets with and without energy price regulation the present Section carries out a comparative analysis of energy markets across all EU Member States, grouped in two categories: markets where energy prices are set in market conditions and markets characterised by intervention in the price setting mechanism. These two groups are appraised using average values for each of the elements considered, weighted by population.

Background: Energy market liberalisation and price regulation

The EU-level liberalisation of the electricity market was initiated with the First Energy Market Directive, which was adopted in 1996. At that time, both the United Kingdom and the Nordic countries had already started to liberalise their markets. Two additional legislative packages have followed since then, i.e. the Second Energy Market Directive in 2003 and the Third Package, including the Third Electricity Directive, in 2009. The process has aimed to separate the network activities, i.e. transmission and distribution, from generation and supply activities. The rules regarding unbundling of these activities into separate entities have become increasingly stringent over this period to properly ensure this separation of activities. This has mainly reflected concerns about the competition, in particular regarding an appropriate pricing of these services as well as fair access to the networks for new entrants.

Following the separation of the different activities in the supply chain of electricity, the price formation of the final end-user price has also changed. The electricity price now consists of different components relating to the different parts of the supply chain, as shown on Figure 1.

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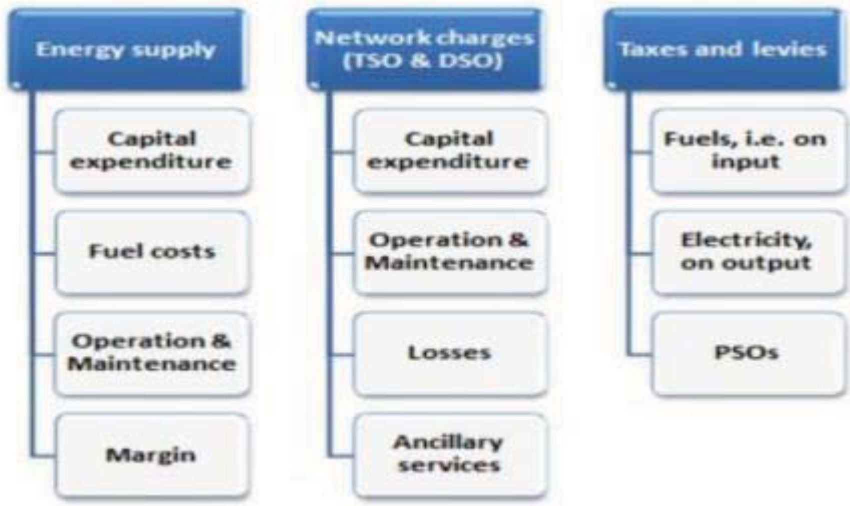
While regulated prices are unlawful under current Gas and Electricity Directives, unless they meet specific conditions, many Member States still apply price regulation.

At the same time it is important to note, as already explained in Section 2 of the present Annex, that electricity and gas price regulation refers only to the 'energy' component of the end-user price, excluding network charges, taxes, other levies and VAT. This component is the element which should be determined by market demand and supply in a fully liberalised energy market.

Figure 1: Different components of the final electricity price



Source: ECFIN

Background: Academic discussion on the merits of energy market liberalisation

A number of academic papers have presented arguments in favour of price regulation in retail energy markets. The assumption presented is that deregulation will not lead to any significant efficiency improvement or added value. The argument presented is that the potential retail savings on activities such as metering, billing or customer services are uncertain and their expected economic impact is too low to be significant for most customers.[149] In addition, it is also argued that customers are reluctant to change[150] and in some cases inability to make appropriate choices.[151]

However, the above mentioned arguments have been refuted by a number of authors. Littlechild argues that domestic customers are not indifferent to choice, and retailing is

[149] *"Why do we need electricity retailers? Or can you get it cheaper wholesale"* (2000) Paul L. Joskow; "The future of retail energy markets" (2008) Catherine Waddams; "The big retail 'bust': what will it take to get true competition?" (2000) Theresa Flaim

[150] *"Consumer preference not to choose: methodological and policy implications"* (2007) Timothy J Brennan

[151] *"Retail competition in electricity markets"* (2009) Christophe Defeuilley

precisely the activity that can lead to products that best suit customers' preferences.[152] Based on the US experience with energy market liberalisation Zarnikau and Whitworth[153], Rose[154] and Joskow[155] demonstrate cost-saving benefits from competition.

Moreover, introducing competition is equivalent to opening the door to innovation. The market can create alternatives to a regulated framework. Those in favour of a regulated retail market assume regulators will set up a pass-through tariff in which the final price of energy will be composed of the cost of wholesale energy plus a margin to cover for the cost of selling the energy to the final customers. However, Littlechild argues that if customers want this option, the market will be able to deliver it. Indeed, as it is already the case in the Nordic Member States, with the roll-out of smart meters, dynamic tariffs, which are similar to the pass-through tariffs, will be available to customers. From this perspective, the advantages of competition are clear.

Other arguments in favour of open retail markets refer the possibility that suppliers introduce new billing options, improve operations of the wholesale market by raising the number of agents involved or provide energy efficiency related services. On the other hand, regulated prices may reduce customer engagement and, in these markets, there is a possibility for Governments to alter electricity tariffs for political gains. More generally, it has been argued that end-user price regulation in electricity and gas markets distorts the functioning of the market and jeopardises both security of supply and the efforts to fight climate change[156].

Assessment of market structure and concentration

Measures of market structure and concentration, such as the number of main suppliers and the market share of largest suppliers, provide an indication of the degree of competition in a market, which is a useful first step to draw a comparison between markets with energy price regulations and those where prices are set by supply and demand. Markets with lower market concentration where a high number of service providers compete to gain and retain customers are under competitive pressure to deliver better deals for consumers. This makes market structure indicators relevant for assessing the performance of energy markets.

Evidence shows that energy markets without price regulation show a higher number of suppliers and less market concentration. In fact, while markets without electricity price regulation have on average 34 nationwide suppliers, markets with regulated prices have 19, as shown on Figure 2. A similar trend can be observed within the gas market, as shown on Figure 4. While markets without gas price regulation have on average 30 suppliers, markets with regulated prices have 17.

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[152] *"Retail competition in electricity markets—expectations, outcomes and Economics"* (2009) Stephen Littlechild

[153] *"Has Electric Utility Restructuring Led to Lower Electricity Prices for Residential Consumers in Texas?"* (2006) Jay Zarnikau, Whitworth

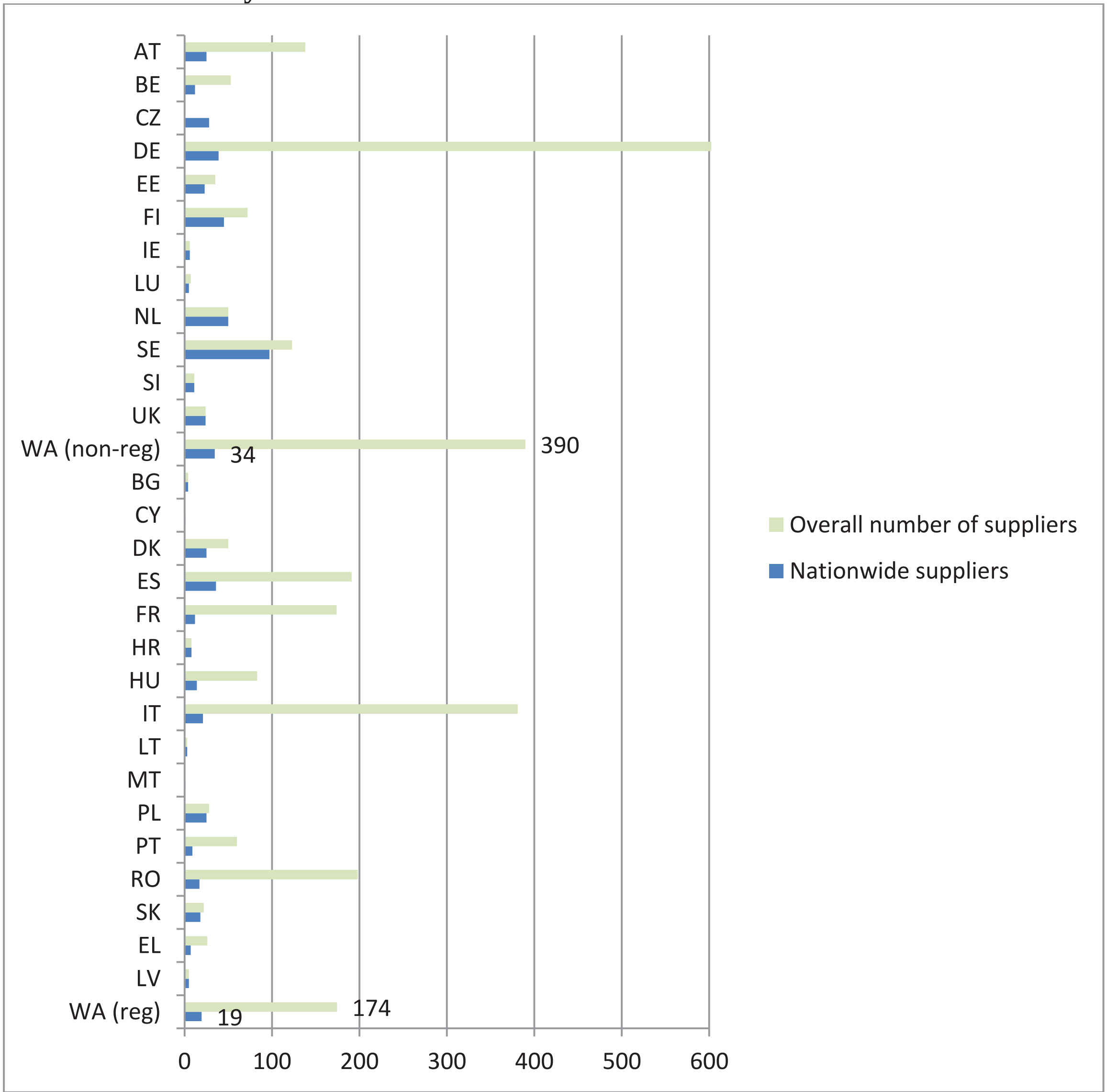
[154] *"The State of Retail Electricity Markets in the US"* (2004) Kenneth Rose

[155] *"Markets for power in the United States: an interim assessment"* (2005) Paul L Joskow

[156] *"Position paper on end-user price regulation"* (2007) European Regulators' Group for Electricity and Gas

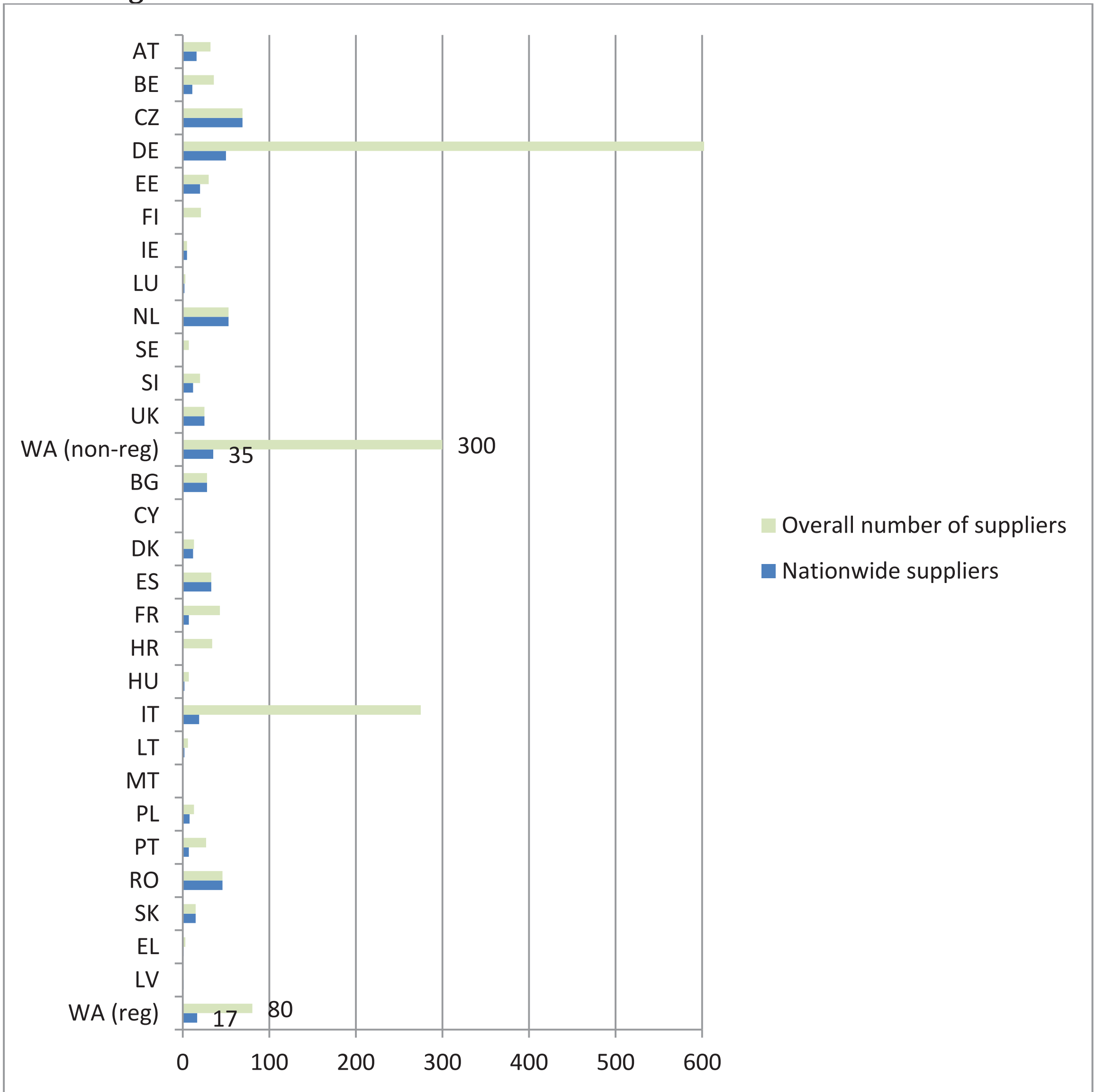
Among the top ten electricity markets in terms of the number of suppliers, seven do not use any form of price regulation, including Sweden (97 nationwide suppliers), the Netherlands (75) and Finland (45). In contrast, among the ten electricity markets with the lowest number of suppliers, eight are characterised by regulated prices, including Cyprus (1 nationwide supplier), Malta (1), Lithuania (3), Bulgaria (4) and Latvia (5).

Figure 2: Overall number of suppliers and number of nationwide suppliers active in the retail electricity market for households



Source: ACER

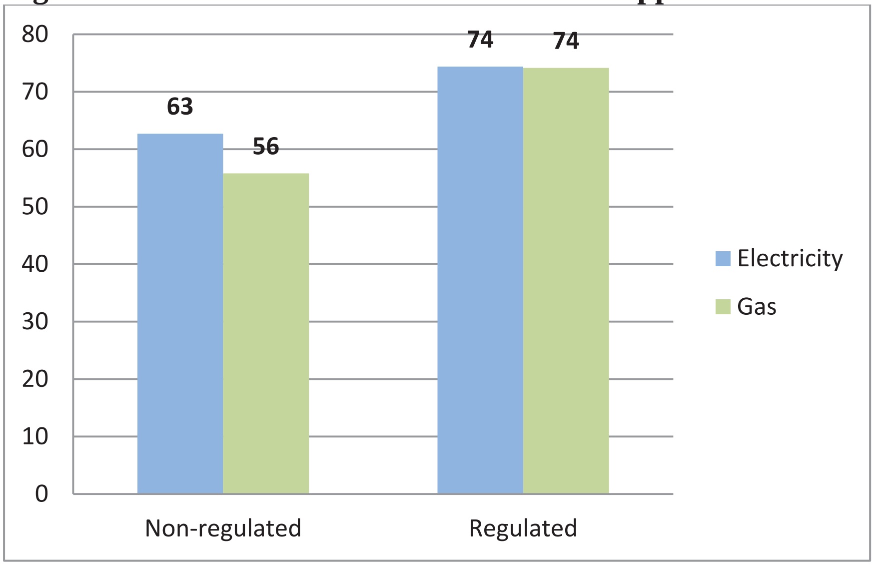
Figure 3: Overall number of suppliers and number of nationwide suppliers active in the retail gas market for households



Source: ACER

Market concentration, measured by the share of the main suppliers in that market, is another key indicator of competitiveness. Main suppliers (i.e. suppliers who have a market share above 5% of the total) in markets without price regulation have a 63% market share in the electricity market and 56% market share in the gas market. Markets with regulated prices see main suppliers covering 74% of the market on average in electricity and gas markets. This data further confirms the advantage of markets without price regulation in terms of their competitive performance.

Figure 4: Cumulative market share of main suppliers



Source: ACER

Assessment of market conduct

Effective retail competition is characterised by competition between suppliers over price and non-price elements whereby suppliers undercut each other's' prices to the efficient cost level, improve the quality of their services and develop innovative products which meet the requirements of customers with a view to increasing market share and profits. In competitive retail markets customers should have the freedom of choice by moving to an alternative supplier, to change contracts or to choose new products. The freedom to choose the energy supplier is key because customer switching activity puts competitive pressure on market actors.

In the present Section all of the above described elements of retail market conduct are analysed for both regulated and non-regulated energy price markets in order to complete the relative performance assessment of these markets.

Price competition

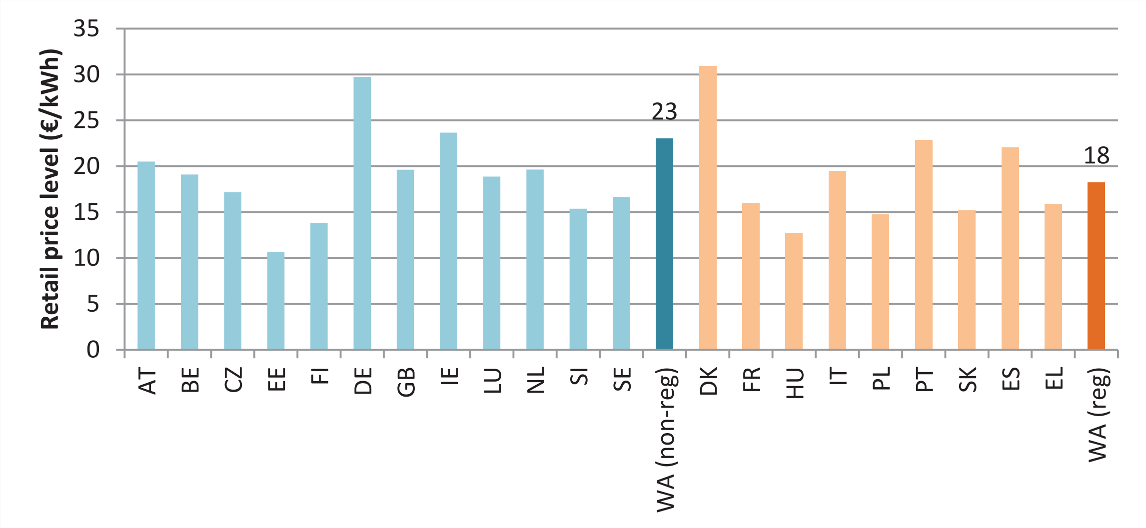
Price competition is typically used as the basic indicator of market competitiveness. Price competition among suppliers is limited to the energy component of the supply price which remains the largest of the three price components despite the fact that this component has generally diminished since 2008 mainly due to increases in the taxes/levies.[157]
Data from the Agency for the Cooperation of Energy Regulators (ACER)[158] shows that Member States without regulated prices have on average slightly higher energy prices

[157] *"Energy prices and costs in Europe"* (2014) European Commission https://ec.europa.eu/energy/sites/ener/files/publication/Energy%20Prices%20and%20costs%20in%20Europe%20_en.pdf

[158] "*Market Monitoring Report 2014*" (2015) ACER, available at http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015.pdf

than those with price regulation. This is not surprising as Member States with regulated prices can set *de facto* the final price on energy services. Price regulation by State authorities can and in some instances does result in prices set below costs, i.e. the end consumer price does not cover the full costs of producing and delivering energy to consumers.

Figure 5: Retail price level across EU Member States, 2014



Source: ACER

Note: Information for Latvia; Bulgaria; Bulgaria, Croatia, Cyprus; Lithuania; Malta; and Romania not available.

While lower retail prices seem to present an immediate advantage to all customers, it is important to analyse the economic sustainability of energy prices regulated below the actual cost and changes to consumer surplus resulting from price regulation.

Cost reflectiveness of regulated prices

Regulated prices can have negative impacts on the energy market especially if they are set too low. First, energy prices which are set too low fail to provide the right signal to energy customers about costs and scarcity, which risk resulting in over-consumption of a cheap service. Second, the low level might hamper the process of market opening by discouraging new companies from entering the market. Third, they will determine the ability of different suppliers to make competitive offers on the wholesale market. For this reason, if end-user prices are set too low, suppliers might not be able to recover their costs and could face potential losses.

By contrast, if set too high, they might not reflect the production costs of the incumbent and increase their rents, while at the same time reducing the surplus of final customers. The result is inefficiencies in the overall energy system.

Determining the proper level of regulated prices requires full information on the cost structure of the industry, which is becoming increasingly difficult as the electricity markets evolve.

In fact, while ensuring cost-reflectiveness of regulated prices could be an option to address negative effects of price regulation, the regulators' ability to set the *right* margin between wholesale and retail prices is limited by imperfect information and rapidly changing market conditions including a wholesale market which is affected by commodity prices, cost of capital and the price of CO2 allowances, to quote just a few. These barriers constitute a significant disadvantage characterising any kind of price regulation, even that which is set "above costs", as there is a high risk that the margins set by the regulators will not be sufficient for new service providers to enter the market. The effect of such miscalculation of the most optimum price level would be less market players and less competition and therefore less innovation and a lower general level of services.

Issue of tariff deficits

Electricity tariff deficits have emerged as an issue for public finances. A tariff deficit implies that a deficit or debt is built up in the electricity sector, often in the regulated segments of transmission or distribution system operators, but in some cases also in the competitive segments, e.g. in incumbent utilities.

A deficit is accumulated due to the fact that the regulated tariffs which should cover the system's operating costs are either set too low or not allowed to increase at a pace that cover rising production or service costs. As these deficits accumulate due to government regulation of tariff or price levels, they have been recognised as contingent liabilities of the State in a few Member States. In these cases, the debt stemming from low energy prices need to be repaid through general taxation from present or future taxpayers.

The results of a study carried out by the Directorate General for Economic and Financial Affairs on the issue of electricity tariff deficits indicates that 11 Member States had accumulated electricity tariff deficits as of 2012[159]. Within that group, 10 Member States continue to regulate their electricity prices, as shown in Figure 7.

Figure 6: Electricity tariff deficit – comparison between Member States

Table 3.1: **Electricity tariff deficit – comparison between Member States**

		ES	PT	EL	FR	IT	DE	BG	MT	RO	HU	LV
Cumulated tariff debt, % of GDP, 2013		3	2.2-2.6	0.4	0.2	0.1*	0.01	1-1.5**	N.A.	0.1*	N.A.	N.A.
Cumulated tariff debt, EUR billion, 2013		30	3.7-4.4	0.7	4	1.5*	0.2	0.4-0.6**	N.A.	0.15*	N.A.	N.A.
Scope of the tariff deficit	- on RES account			✔		✔	✔					
	- on PSO account				✔							
	- of access costs	✔										
	- of integral tariff		✔					✔				
	- tariff below costs				✔			✔	✔	✔	✔	✔
Deficit recognized by the authorities or energy regulator?		✔	✔	✔	✔	✔	✔					
Deficit cumulative (i.e. not settled in the following period)?		✔	✔	✔	✔	✔		✔	✔	✔		

Note:
* 2012, ** World Bank forecast

Source: Commission Services

Source: DG ECFIN, European Commission

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[159] *"Electricity Tariff Deficits. Temporary or permanent problem in the EU?"* (2014) European Commission

Cumulated tariff debts are substantial in some Member States. In Spain and Portugal, where electricity prices are regulated, the tariff debt represented 3% and 2.2-2.6% of the GDP respectively.

Link between wholesale and retail prices

While regulated price markets show an advantage over unregulated price markets in terms of the final price for the consumer, research carried out by the European Parliament shows that the relationship between wholesale and retail prices for households is weaker in countries with price regulation.[160] Whilst retail household prices appear to be positively related to wholesale prices for both groups of countries, the link for countries with price regulation is less pronounced based on the estimated coefficients. This indicates that regulated prices may weaken the link between wholesale prices and retail prices, or at least tend to delay it. While this could delay or prevent the increase of household prices when wholesale prices are high, it may also imply that households cannot fully benefit from a decrease in wholesale prices.

Ensuring an effective link between wholesale and retail energy prices is key for delivering the benefits of the wholesale energy market competition to energy consumers. To give a sense of perspective, the European Commission 2014 report on the "Progress towards completing the Internal Energy Market" found that wholesale electricity prices in the EU declined by one-third and wholesale gas prices remained stable between 2008 and 2012.[161]

Protection of vulnerable consumers and the energy poor

Continuous price regulation in some Member States is justified on the grounds of protection of vulnerable consumers and the energy poor. In this context, it is argued that energy price regulation is necessary to protect customers from the market power of energy monopolies. This is because an unregulated monopoly could charge customers a price much higher than its production cost. Similar arguments have been put forward with respect to vulnerable customers.

However, evidence shows that blanket energy price regulation is not an optimal protection measure for vulnerable consumers from the point of view of efficient allocation of public resources. The above is based on the assumption that deficits associated with energy prices regulated below-costs are financed from the State budget. In fact, under regulated energy price environments public resources are often used to support all households, regardless of their income or vulnerability. The efficiency of such approach is questionable as even the distribution of benefits associated with low regulated energy prices results in higher income groups receiving higher public support than lower income groups, as evidenced in Figure 7 below, which shows that top earners in most Member States consume more electricity than the lowest income groups. Higher energy consumption among top income groups occurs despite the assumed higher

[160] *"The impact of oil price on EU energy prices"* (2014) European Parliament

[161] "*Communication on progress towards completing the Internal Energy Market*" European Commission COM(2014) 634 final

efficiency of dwellings inhabited by these income groups and higher energy efficiency of appliances typically used.

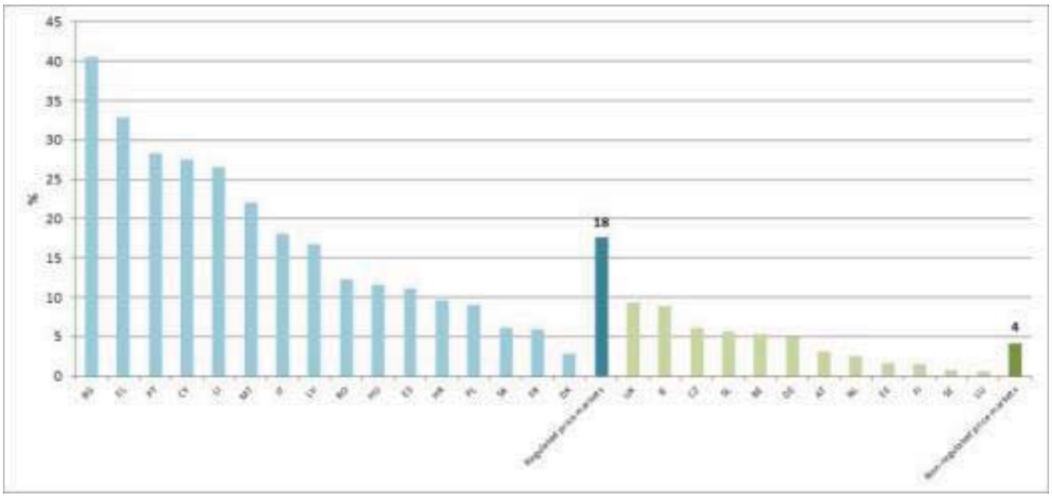
Figure 7: Electricity consumption per income group

electricity									
TWh/Quintile									
		Min_p / Max Q							
MS	Last obs Y	Q_1	Q_2	Q_3	Q_4	Q_5	Total	Share [Q3;Q5]	Share [Q5]
AT	2010	2.5317	3.0301	3.6029	4.1585	4.7198	18.0429012	69.17	26.16
BE	2014	3.7848	4.3654	4.9736	5.1633	6.0783	24.3654214	66.55	24.95
BG	2014	1.8161	1.9771	2.0471	2.3799	2.3553	10.5755563	64.13	22.27
CY	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
CZ	2014	4.9008	4.7586	4.7242	4.6512	4.6011	23.6357537	59.13	19.47
DE	2013	14.8852	19.2219	24.5255	29.7412	35.1913	123.564998	72.40	28.48
DK	2014	1.4548	2.0504	2.2440	2.3280	3.0378	11.1149013	68.46	27.33
EE	2012	0.2111	0.2751	0.3492	0.4402	0.6445	1.92015702	74.68	33.57
EL	2014	1.9987	2.3096	2.6036	2.8719	3.2565	13.0403713	66.96	24.97
ES	2014	10.7711	13.1299	15.0333	16.4261	19.1277	74.4881824	67.91	25.68
FI	2012	1.7214	2.7925	3.6704	5.2136	7.5286	20.9265293	78.43	35.98
FR	2011	29.6126	33.9193	37.2348	42.4051	52.4225	195.594225	67.52	26.80
HR	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
HU	2014	1.5453	1.8989	2.3589	2.8177	3.1565	11.7773296	70.76	26.80
IE	2010	1.4156	1.8064	2.0748	2.3413	2.5326	10.1706472	68.32	24.90
IT	2014	12.2328	13.0597	13.2631	14.1195	14.6320	67.3071007	62.42	21.74
LT	2012	0.5790	0.4817	0.5090	0.5239	0.5544	2.64797763	59.94	20.94
LU	2013	0.1836	0.2325	0.3155	0.2818	0.3067	1.32017006	68.48	23.23
LV	2014	0.3551	0.3211	0.3466	0.5103	0.4600	1.99303232	66.08	23.08
MT	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
NL	2013	10.1102	11.1071	12.6973	14.6148	16.8544	65.3836495	67.55	25.78
PL	2014	4.8701	6.0313	7.0604	8.2860	9.8964	36.1441731	69.84	27.38
PT	2010	2.6357	2.8525	3.1092	3.4401	4.5354	16.5727938	66.88	27.37
RO	2014	1.6464	2.3104	2.8959	3.3612	3.9355	14.1494067	72.04	27.81
SE	2012	3.2397	4.4504	6.1886	8.1432	10.0573	32.0791578	76.03	31.35
SI	2012	0.6814	0.7766	0.9146	0.9833	1.1003	4.45618993	67.28	24.69
SK	2014	0.8997	1.2671	1.5558	1.7263	1.9268	7.37562799	70.62	26.12
UK	2014	21.6071	24.6902	26.1358	28.2850	32.7540	133.472173	65.31	24.54

Source: DG ENER

It can be argued that if resources previously allocated to finance below-cost price regulation are used for targeted support of vulnerable consumers, a higher impact can be achieved in terms of the protection of vulnerable consumers. This conclusion is supported by evidence presented in Figure 8 which shows that consumers in unregulated price markets feel more able to maintain an adequate level of heat during winter. This data also shows that energy price regulation is not an effective means of addressing energy poverty.

Figure 8: Percentage of population unable to keep their homes warm during winter, 2014



Source: DG ENER

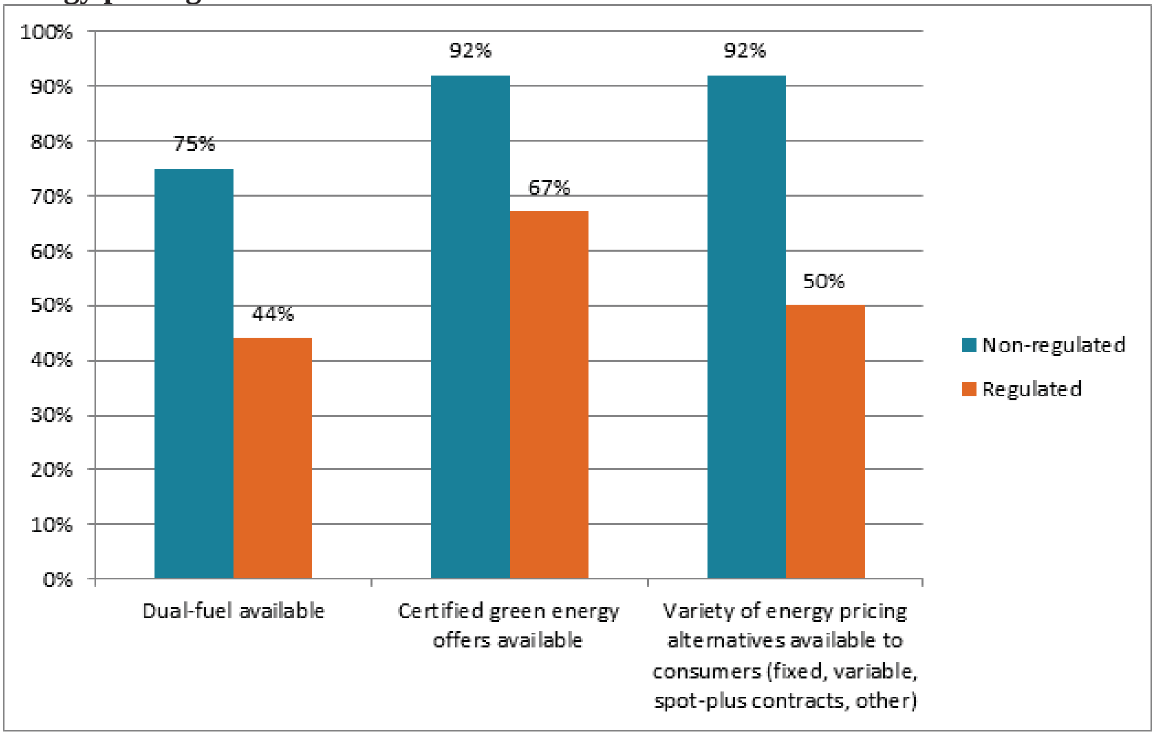
Non-price competition/innovation

Although low prices are the most commonly thought of way for firms to attract consumers, suppliers may also seek to distinguish their products by other means. These may include quality of service, convenience, an environmentally sustainable product, or any other non-price aspect that adds value for consumer and brings innovation to the retail energy market. The diversity of products available in a market is therefore also a good indication of the health of competition.

Conversely, when prices are kept artificially low customer surplus may be reduced as some customers are able and willing to pay higher prices for better and more innovative energy services. In that context regulated prices might deprive those customers from accessing more offers and more innovative and complex services such as certified green energy offers, loyalty programmes, access to new technologies such as smart metering and mobile apps, or non-financial benefits such as free maintenance of water boilers or home insurance which are delivered by some retailers within the energy market.

In fact, data displayed in Figure 9 shows that customers in markets where prices are not regulated have access to more diverse services and a wider choice of offers. Dual fuel offers are available in 75% of the markets without price regulation and only in 44% in those with regulated prices. Certified green energy offers are available in 92% of the markets without price regulation and in 67% of the markets with regulated prices. Only 50% of markets with regulated prices offer energy pricing alternatives, while this option is available in 92% of markets without price regulation.

Figure 9: Share of Member States with dual-fuel, certified green and variety of energy pricing tariffs



Source: ACER

Markets without price regulation are also characterised by retail energy markets delivering more financial and non-financial benefits and a greater availability of information and communication technologies in association with energy contracts, as showed in Figure 10.

Figure 10: Retail market innovation

	number of electricity only offers	dual-fuel available	certified green energy offers available	availability of non-price financial benefits	availability of non-financial benefits	ICT offer	Variety of energy pricing alternatives available to consumers
Austria	53	Yes	Yes	Yes	Yes	Yes	Yes
Belgium	20	Yes	Yes	Yes	No	Yes	Yes
Bulgaria	1	N/A	N/A				No
Croatia	4	N/A	N/A				Yes
Czech Republic	69	Yes	Yes				Yes
Cyprus	1	N/A	N/A				No
Denmark	83	No	Yes	Yes	No	Yes	Yes
Estonia	40	Yes	No				Yes
Finland	401	No	Yes	Yes	Yes	Yes	Yes
France	22	Yes	Yes				Yes
Germany	404	No	Yes	Yes	No	Yes	Yes
Great Britain	69	Yes	Yes	Yes	Yes	Yes	Yes
Greece	7	No	No				Yes
Hungary	4	No	No				No
Ireland	9	Yes	Yes	Yes	Yes	Yes	Yes
Italy	23	Yes	Yes	Yes	Yes	Yes	Yes
Luxembourg	18	Yes	Yes				Yes
Latvia	1	N/A	N/A				No
Lithuania	1	N/A	N/A				No
Malta	1	N/A	N/A				No
Netherlands	86	Yes	Yes	Yes	No	Yes	Yes
Poland	133	No	Yes				Yes
Portugal	34	Yes	Yes				Yes
Romania	1	N/A	N/A				No
Slovakia	23	No	No				No
Slovenia	5	Yes	Yes				No
Spain	54	Yes	Yes	Yes	Yes		Yes
Sweden	378	No	Yes	Yes	Yes	Yes	Yes

Source: ACER/CEER, VaasaETT

Data presented above further confirms that markets where prices are set according to supply and demand perform better in terms of bringing innovation to the retail energy market– deliver greater choice and more innovative services and offers, than markets where energy prices are regulated.

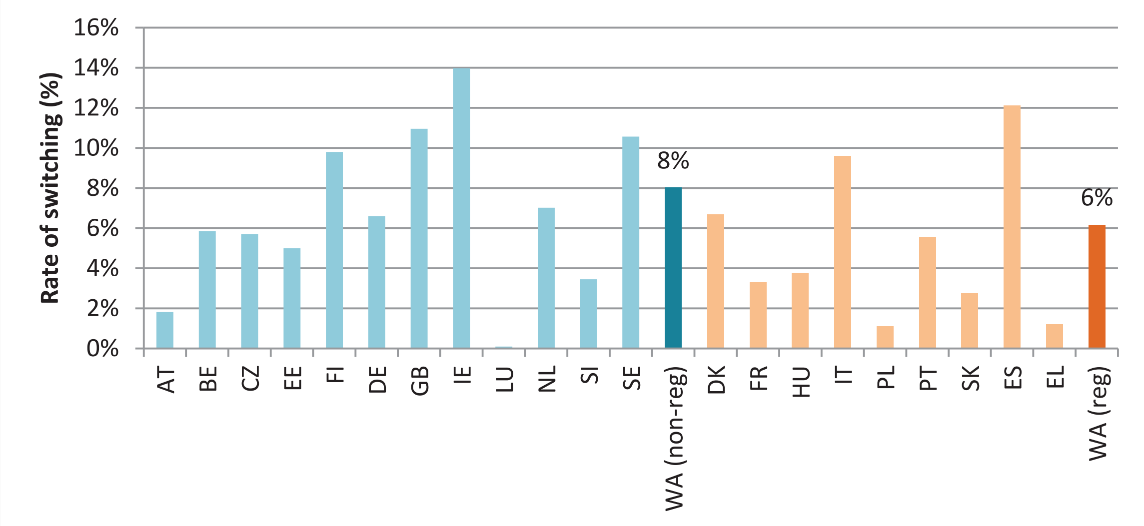
Customer switching activity

Customer switching activity puts competitive pressure on suppliers and therefore is an important indicator of competition within the market.

ACER data presented in Figure 11 and 12 shows that markets with no price regulation show higher customer activity both in terms of external switching (movement between suppliers) and internal switching (movement between alternative products from the same supplier) than markets with regulated prices.

On the other hand, electricity switching rates in markets with price regulation are significantly lower. In Malta, Cyprus, Bulgaria, Latvia, Lithuania and Romania switching rates remained at zero, mainly due to the lack of retail competition or very weak competition and limited choice available to customers.

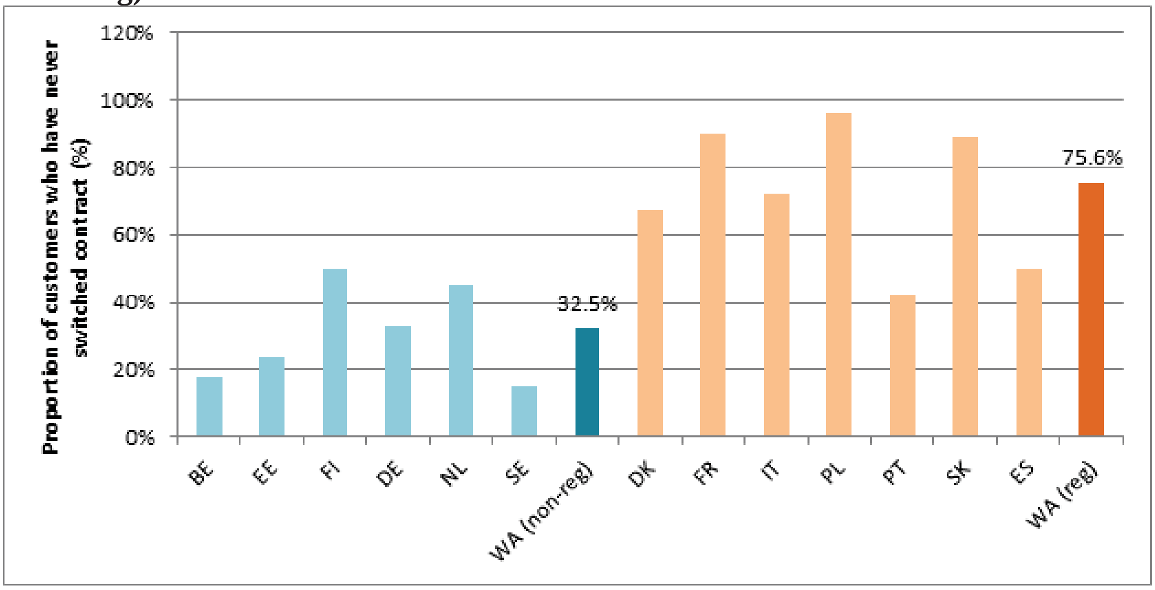
Figure 11: Customer external switching rates



Source: ACER

Customers in regulated price markets also display lower internal switching rates – a phenomenon which can be explained by more restricted choice of offers in those markets. In fact, Figure 12 shows that 75% of customers in markets with price regulation have never switched contracts, in comparison to 32,5% in markets with no price regulation.

Figure 12: Proportion of customers who have never switched contract (internal switching)

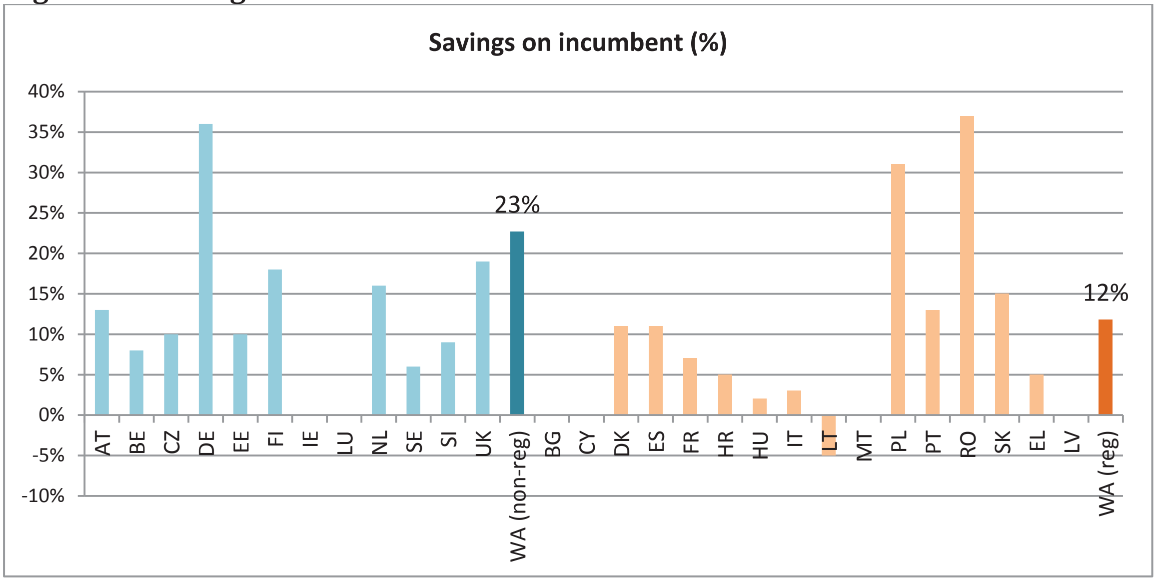


Source: ACER

Low switching rates in markets with price regulation represent a lost opportunity for savings for many customers. **In fact in most markets customers can derive**

substantial benefits from switching, as illustrated in Figure 13. In markets without price regulation customers can save on average 23% of their energy bill by switching from the incumbent. Potential savings in markets with price regulation amount to 12% on average.

Figure 13: Savings on incumbent



Source: ACER

Assessment of customer experience

Customer experience is key to appraising the comparative performance of different types of markets. Variables which compose customer experience and are analysed in this Section include comparability of offers, trust in retails to respect the rules and regulations protecting customers, the degree to which customer expectations are met and customer satisfaction with the choice.

The above variables are measured by the Consumers, Health, Agriculture and Food Executive Agency (CHAFEA) as part of the Market Monitoring Survey. The report surveys 42 markets in the 28 Member States of the EU, as well as Norway and Iceland, with the general aim to assess customer experiences and the perceived conditions of the customer markets in all EU Member States. The assessment is measured through a "Market Performance Indicator" (MPI) which is a composite index indicating how well a given market performs, according to customers.

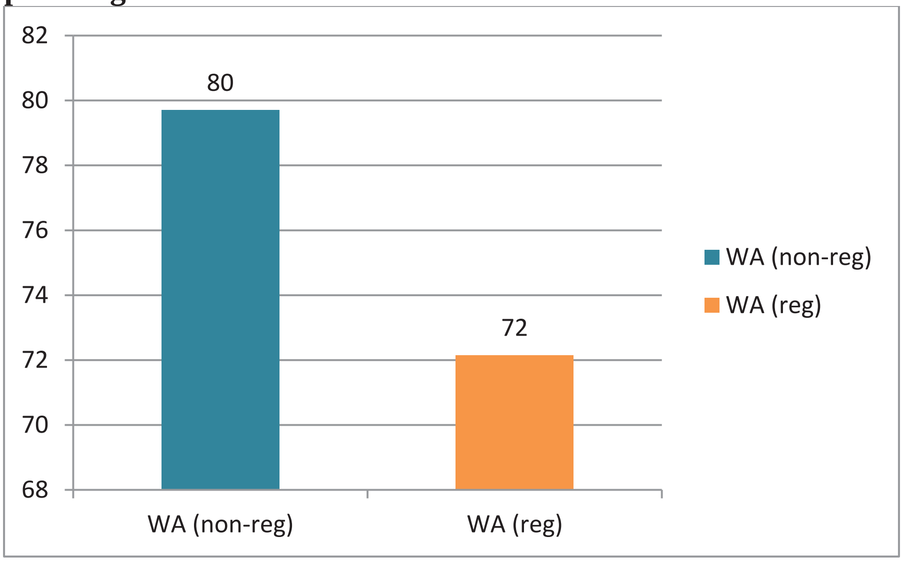
The overall MPI score for the market for “electricity services” across the EU is 75.3 points, based on a maximum possible score of 100 points. Electricity services market scored 3.3 points lower than the services markets average. This makes it a low performing services market, ranking 26th of the 29 services markets. The overall MPI score for the market for “gas services” at EU28 level is 78.1, which is lower than the services markets average score by 0.5 points. This makes it a middle to high performing services market, ranking 14th of the 29 services markets.

In comparison to the services markets average, the “electricity services” market has a higher proportion of complaints and higher detriment score, measuring customers experiencing problems with the products or services they purchased. The electricity services market also performs worse than average in terms of the comparability of offers, customers' trust in suppliers, the capacity to meet customers' expectations, and the ability of the market to deliver sufficient choice. It is also characterised by a lower than average switching activity.

At the same time, there is a 34.1 point difference in MPI between the top ranked country and the lowest ranked country, indicating that there are considerable country differences to be taken into account when evaluating the electricity services market. The market scores higher in the EU15 and lower in the EU13 compared to the EU28, while performing especially well in the Western and Northern regions.

In comparison to the services markets average, the "gas services" market scores above the average for the problems, detriment and expectations components. However, the comparability and choice components are lower. The "gas services" market also has a lower than average switching proportion.

Figure 14: Market Performance Indicator for electricity markets with and without price regulation

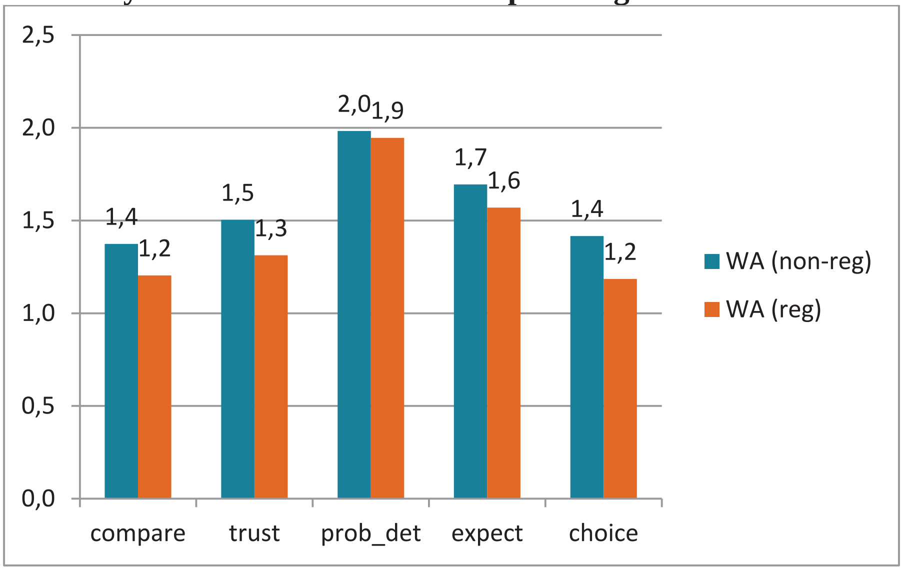


Source: EC, DG JUST[162]

The MPI scores for 2015 indicate a clear advantage of markets without price regulation over those with regulated prices in terms of customer satisfaction. As shown in Figure 14, markets without price regulation scored on average 80 points, while those with price regulation scored 72. The advantage of markets without price regulation over those with regulated prices was equally spread across all five components analysed, as shown in Figure 15.

[162] *"Monitoring Customer Markets in the European Union 2013 – Part III (Electricity)"(2013)* European Commission

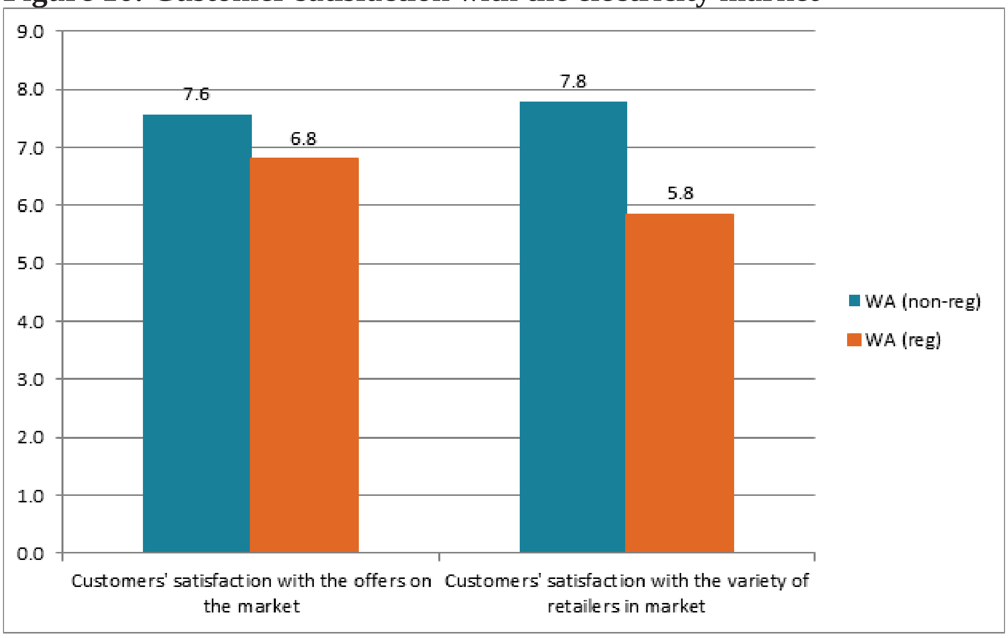
Figure 15: Market Performance Indicator for electricity markets per component for electricity markets with and without price regulation



Source: EC, DG JUST

The 2013 edition of EU market surveys provides an insight into general customer satisfaction with the electricity market, as shown in Figure 15. Markets without price regulation scored 7.6 and 7.8 on average for customer satisfaction with the offers on the market and with the variety of suppliers, while markets with price regulation scored 6.8 and 5.8 points respectively. This data confirms a clear advantage of markets without price regulation from the customer point of view.

Figure 16: Customer satisfaction with the electricity market



Source: European Commission (2013)

Conclusion of the assessment

In this Section we have methodically screened the performance of markets with and without price regulation based on a number of competitiveness indicators and market surveys which measure market competitiveness and customer satisfaction with the electricity and gas markets. The analysis indicates that electricity and gas markets where prices are set by supply and demand are able to deliver better and more diverse services to the customers. In fact, despite slightly higher prices in markets without price regulation, customers in these markets show a higher level of satisfaction as they have a wider choice and access to better quality services which are more reflective of their preferences.

The analysis nonetheless suffers from clear limitations such as selection bias. It might well be that the Member States in the category of non-regulated prices have lower market concentration, higher switching rates or better customer experience for reasons different than price regulation. However, despite the methodological weaknesses of the analysis, the results are comparable with the results of research carried out by ACER in its Market Monitoring Report.

In fact, in order to achieve a full picture of energy market competitiveness which is not dependent on a single indicator ACER produced a single composite index ('ACER Retail Competition Index – ARCI') which provides a comprehensive picture of the relative competition performance of the retail electricity and gas household markets in each Member State. The indicator combines several elements, including market concentration, entry/exit activity, switching, consumer satisfaction and mark-ups (see Table 2 below). As such the indicator covers all of the individual components used to analyse the performance of markets with and without electricity and gas price regulation.

Table 2: Competition indicators included and the assessment framework for the composite index

Indicator	Scope	Low score = 0	High score =10	Weight
Concentration ratio, CR3	National	Market share of three largest suppliers 100%	Market share of three largest suppliers 30% or less	10
Number of suppliers with market share > 5%	National	Low number of suppliers	High number of suppliers	10
Ability to compare prices easily	National	Difficult to compare prices	Easy to compare prices	10
Average net entry (2012-2014)	National	Net entry zero	Net entry of five or more nationwide suppliers	10
Switching rates (supplier + tariff switching) over 2010-2014	National	Annual switching rate zero	Annual switching rate 20% or more	10
Non-switchers	National	None have switched	All have <1/3 not switched	10
Number of offers per supplier	Capital city	One offer per supplier	Five or more offers per supplier	10
Does the market meet expectations	National	Market does not meet expectations	Market fully meets expectations	10
Average mark-up (2012–2014) adjusted for proportion of consumers on non-regulated prices	National	High mark-up	Low mark-up	10

Source: ACER

According to the index, the most competitive markets for households are electricity markets in Sweden, Finland, the Netherlands, Norway and Great Britain and gas markets in Great Britain, the Netherlands, Slovenia, the Czech Republic and Spain. The index shows weak retail market competition in electricity household markets in Latvia, Bulgaria and Cyprus and gas household markets in Lithuania, Greece and Latvia.

The results of the ACER analysis, presented also in Figure 14, indicate that the level of competition in markets with regulated prices for households is much lower than in countries that do not regulate electricity and gas prices, with the exceptions of the gas markets in Spain and Denmark. Therefore the ACER indicator confirms the overall findings of the analysis of the performance of markets with and without price regulation carried out in the present Section.

Figure 17: ACER Retail Competition Index (ARCI) for electricity and gas household markets – 2014

Source: ACER

Comparison of options for price deregulation

Table 3: General comparison of the options

	0. Non legislative: Making use of existing *acquis* to continue bilateral consultations and enforcement actions, accompanied by EU guidance	**1. Legislative obligation: No price regulation but social tariffs allowed**	**2a Legislative obligation: Price regulation allowed below certain consumption threshold**	**2b. Legislative obligation: Cost covering price regulation allowed without limitation as to the amount of energy consumed**
Time limitation	End date to be set by each Member State in compliance with EU acquis to be assessed on case-by-case basis.	End date set in EU legislation for all price regulation (except social tariffs)	End date set in EU legislation for price regulation above a certain consumption threshold. No end date for price regulation below the defined threshold.	End date set in EU legislation for price regulation below costs No end date for price regulation below the defined threshold.
Limitation as to the scope of beneficiaries	Scope of beneficiaries to be defined by each Member State in compliance with EU acquis to be assessed on case-by-case basis.	No beneficiaries of price regulation. Social tariffs allowed as transitional measure	Beneficiaries of price regulation limited to households below a certain consumption threshold	No limitation as regards the scope of beneficiaries (all households).
Methodology for setting the price	Methodology to be defined by each Member State in compliance with EU acquis to be assessed on case-by-case basis.	No provisions as regards methodology (cost coverage etc.) necessary as all price regulation is to be phased out.	Methodology to be defined by each Member State in compliance with EU acquis to be assessed on case-by-case basis.	Principles ensuring cost coverage (e. g. at least positive mark-ups or costs of an efficient supplier plus a reasonable profit margin) to be defined in EU legislation while concrete methodologies would be developed at national level.
Level of harmonisation	Allows a case-by-case assessment of the price regulation regimes as well as of the eventual exemptions.	Harmonised end date for blanket price regulation. Allows a case-by-case assessment of the exemptions to price deregulation (targeted price regulation for vulnerable consumers).	Harmonised end date for blanket price regulation. Harmonised exemptions to price deregulation (based on a consumption threshold).	Harmonised end date for blanket price regulation. Harmonised exemptions to price deregulation (based on a price threshold).

Option 0

Option 0 consists of making use of the existing *acquis* to continue bilateral consultations and enforcement actions to restrict price regulation to proportionate situations justified by general economic interest.

Costs

The main costs of this option are those of adapting price regulation regimes in Member States following a case by case assessment by the Commission services via bilateral consultations followed by infringement actions where appropriate based on the current EU acquis. This option would result in different national regimes of price intervention (in terms of applicability in time, to the scope of beneficiaries and definition of price regulation) or a complete removal thereof, assessed on a case-by-case basis in terms of compliance with the EU acquis including as regards proportionality of the measure for achieving the pursued general interest objectives. It is therefore difficult to estimate the costs associated with the implementation of each regime.

The resulting diversity of regimes would create/maintain uncertain prospects for businesses which discourages cross-border supply activities.

The lack of a level playing field across the EU in terms of price setting procedures translates into administrative costs for entering and conducting business in new markets.

Member States with no price regulation will not be affected by the implementation of this option. Therefore no economic impacts are to be expected.

Benefits

While overall the competition on retail markets would improve compared to the existing situation due to the limitation or complete removal of price regulation in Member States, market distortions would continue to exist impacting national markets as well as cross-border competition.

Consumers' benefits linked to price deregulation (more consumer choice for suppliers and energy service providers, better services and resulting increased consumer satisfaction) would vary according to the national price intervention regime/the lack thereof.

Option 1

Option 1 consists of requiring Member States to progressively phase out price regulation for households by a deadline specified in new EU legislation, while having the right to allow transitional, targeted price regulation for vulnerable customers (e. g. in the form of social tariffs).

Social tariffs are a form of regulated prices, usually below market level, available to specific groups of vulnerable customers, notably the energy poor, to ensure that these customers have access to energy at affordable prices.

A social tariff can apply to electricity and/or gas (or any other fuel). The illustrative analysis of costs and benefits for this option will focus on electricity.

Costs

The main cost components of this option are associated with the potential introduction of a targeted price regulation for vulnerable consumers, such as through the social tariff. Member States already applying social tariffs (BE, BG, CY, FR, DE, GR, PT, RO, ES, UK) would not be affected by the implementation of this option.

The estimation of cost and benefits of Option 1 is made in comparison to the free market option (with no regulated prices of any kind or social tariff) for Member States which currently do not use "social tariffs" as a form of protection of vulnerable consumers.

The estimations provided are for illustrative purposes only. The final amount of targeted electricity and/or gas, number of households and level of subsidies can be varied depending on the preferences of the Member State implementing the measure.

Table 4 below shows the average annual electricity consumption and average annual expenditure on electricity which are the two variables used to estimate the cost of introducing social tariffs.

Table 4: Average annual household electricity consumption and expenditure, 2014

Member State	Average annual electricity consumption	Average annual expenditure on electricity
	kWh/HH	EURO/HH
BG	3836	275
CY	4935	920
DK	4288	439
ES	3855	687
FR	5204	499
GR	3953	471
HR	3712	374
HU	2522	233
IT	2494	375
LT	2025	180
LV	2099	180
MT	4266	553
PL	2010	221
PT	2935	377
RO	1590	144
SK	2682	330

Source: INSIGHT_E

The cost of implementing a social tariff depends on the scope of beneficiaries, the difference between the market-based price of energy and the advantageous price set for the beneficiaries of social tariffs as well as on the amount of energy consumption to be covered by the social tariff.

For the purpose of this analysis, the beneficiaries of the social tariff are defined as the share of the population unable to keep warm (according to EU-SILC 2014). The level of the social tariff is defined as 20% less than the regular electricity price (which is shown as the average 2014 nominal price without taxes and levies). There would be no cap on the amount of energy consumption covered by the social tariffs for the defined beneficiaries.

However, in reality Member States would be able to decide on all of the above elements according to their national circumstances. This means that Member States would be able to decide on a more restraint or larger group of beneficiaries, a specific discount level defining the price level under social tariffs and/or set a cap on energy consumption beyond which market prices apply.

Within Option 1 various sub-options can be explored with respect to financing the implementation of the social tariffs, such as:

A- financing only by non-vulnerable households,
B- financing by all households and
C- financing by all electricity customers (including industry, commercial sectors, and all households including vulnerable households).

However, it is important to bear in mind that a levy only on industrial customers would not be desirable as this would make industry less competitive. The final tariff would still vary for vulnerable (eligible households) and other household customers as the base price for the regular tariff and the social tariff remains the same in each instance. Of course, the social tariffs can also be financed in part or in whole through the government budgets and this option could be explored in addition (i.e. financial transfers).

The table and figures below show the costs or savings (net benefits) of the introduction of a tariff, with savings arising for households receiving the social tariff and costs for those paying for the tariff measure. Costs and benefits are calculated for each of the above defined sub-options for financing: A, B and C.

As shown in the summary table below, the costs to finance the social tariff will see an increase in the electricity bills from 1-14% depending on electricity prices, share of vulnerable consumers and average electricity consumption in each Member State. The increase in the electricity bills as result of the implementation of the measure is expected to be highest in BG, GR, CY and PT if the financing is done via all non-vulnerable households or all households. Financing the measure across all electricity consumers allows alleviating the increase in energy bills thus limiting the impact on individual customers.

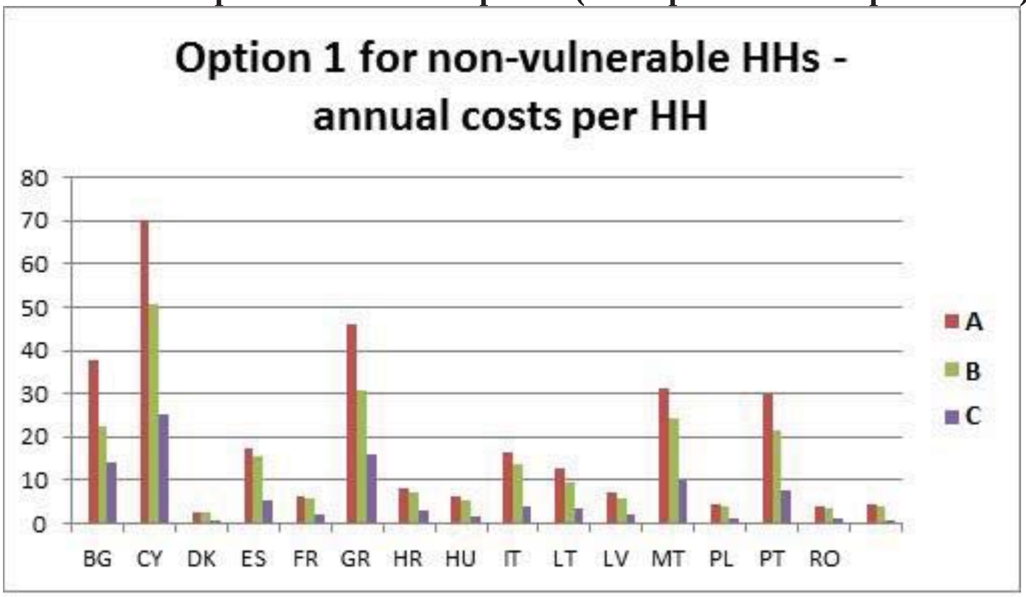
Table 6: Comparison of differences in tariffs to vulnerable and non-vulnerable households for Option 1 according to different financing models

	A - Financing across all non-vulnerable households		B - Financing across all households		C - Financing across all electricity consumers	
	Non-vulnerable Households (regular tariff)	Vulnerable Households (social tariff)	Non-vulnerable Households (regular tariff)	Vulnerable Households (social tariff)	Non-vulnerable Households (regular tariff)	Vulnerable Households (social tariff)
BG	14%	-20%	8%	-10%	3%	-16%
CY	8%	-20%	6%	-13%	2%	-18%
DK	1%	-20%	1%	-19%	0%	-20%
ES	2%	-20%	2%	-17%	1%	-19%
FR	1%	-20%	1%	-19%	0%	-19%
GR	10%	-20%	7%	-12%	2%	-17%
HR	2%	-20%	2%	-18%	1%	-19%
HU	3%	-20%	2%	-17%	1%	-19%
IT	4%	-20%	4%	-16%	1%	-19%
LT	7%	-20%	5%	-13%	2%	-18%
LV	4%	-20%	3%	-16%	1%	-19%
MT	6%	-20%	4%	-14%	1%	-18%
PL	2%	-20%	2%	-18%	0%	-19%
PT	8%	-20%	6%	-13%	1%	-18%
RO	3%	-20%	2%	-17%	1%	-19%

Source: INSIGHT_E

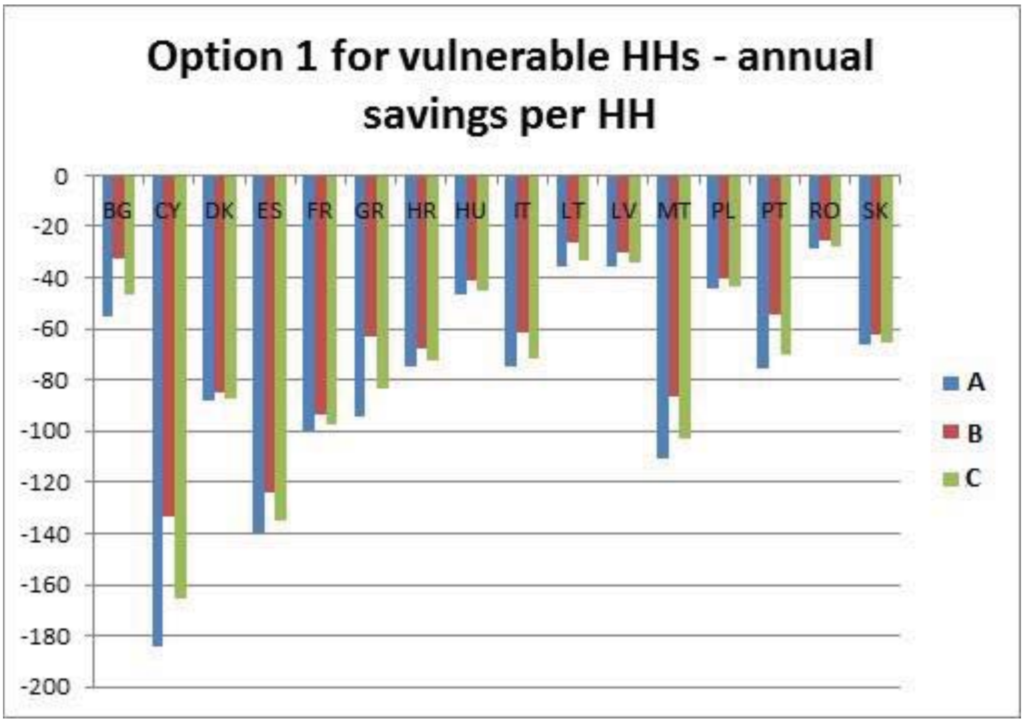
Figure 17 and 18 further explore the nominal costs and benefits per vulnerable and non-vulnerable household.

Figure 17: Comparison of annual costs per non-vulnerable household to finance social tariffs implemented under Option 1(EUR per household per annum)



Source: INSIGHT_E

Figure 18: Comparison of annual savings per vulnerable household benefiting from social tariffs implemented under Option 1(EUR per household per annum)



Source: INSIGHT_E

Other costs related to the implementation of this option would be those associated with the adoption and implementation of deregulation roadmaps in Member States applying price regulation.

Benefits

This option delivers benefits linked to price deregulation in the form of a more competitive retail energy market and the associated wider consumer choice of suppliers and energy service providers and access to a larger variety of products, services and offers, thus increasing consumer satisfaction, as demonstrated earlier in the present Section, under subheading 5a.

At the same time the option to provide transitional and targeted price regulation to clearly defined vulnerable consumer groups would provide the means for achieving the objective of consumer protection during the period of market adjustment. After the period of adjustment, transitional price regulation for targeted groups could be replaced by social policy measures.

Moreover, suppliers would benefit from a level playing field across the EU in terms of a regulatory environment which would encourage cross-border competition. For suppliers in Member States applying price regulation, implementation of this option would lead to a decrease in total costs due to the removal of compliance costs related to setting and submitting for approval/applying regulated prices as set by the national authorities.

Allowing regulated prices (e. g. in the form of social tariffs) targeted at specific groups of vulnerable consumers, notably the energy poor, would also contribute to ensuring universal access to affordable energy services as required under UN-backed Sustainability Development goals.

Summary of costs and benefits for Option 1

The table below summarises the costs and benefits associated with the implementation of Option 1. It reveals that costs of the measure would vary depending on the chosen financing model, leading to an increase in the electricity tariff of non-eligible customers by 1-15%. Vulnerable households eligible for social tariff save on average 20% on their annual electricity bills.

Table 7: Option 1 - Cost and Benefits

	Costs		Benefits	
Measure	**Description**	**Quantification**	**Description**	**Quantification**
Targeted price regulation for vulnerable customers in the form of social tariffs.	Social tariffs in place for a targeted customer group (usually less than 20% of the population) accompanying the transition towards market base prices.	Depending on the financing model (the current examples are cost-neutral to government), those on the regular tariff will see an increase in their electricity tariff by 1-15%.	Allowing price regulation exclusively for clearly defined vulnerable customer groups would ensure that it is a targeted and transitional measure. Benefits linked to price deregulation: wider consumer choice, innovation in the retail energy market linked to increased competition, better quality of services, increased consumer satisfaction.	Vulnerable households save 20% on their annual electricity bills.

Box 1: Impacts on different groups of consumers

The benefits of the measures contained in the preferred option (Option 1), described in detail in the preceding pages, accrue overwhelmingly to households who would qualify for targeted social tariffs and/or other targeted social support measures i.e. vulnerable and/or energy poor consumers. The biggest losers from the measures in the preferred option are high-volume, often higher-income consumers who have in the past benefitted from retail prices that have been set at artificially low levels (see Table 6 and Figures 17 and 18, above). The measures can therefore be considered progressive in nature i.e. they tend to redistribute surplus from relatively high-income ratepayers to increase the welfare of lower-income ratepayers.

Nevertheless, it is also important to remember that in Member States where costs of social tariffs are covered through a tax or a levy on the electricity bill, the social tariff regime places a disproportionately high burden on low-income consumers who are just above the threshold for qualifying for a social tariff. In contrast, direct financial support that is financed through income taxation would avoid this and place a higher burden on those with broader shoulders. For this reason, when it comes to the most effective means of fighting energy poverty, well-targeted social policy measures and investments in energy efficiency, rather than social tariffs, are essential

Option 2a

Option 2a consists of requiring Member States to progressively phase out price regulation for households above a certain consumption threshold to be defined in new EU legislation or by Member States, with support from Commission services.

Costs

The main costs associated with the implementation of this option are linked to the financing of the subsidised energy amount for all beneficiaries of the measure (all households).

For the purpose of this analysis we assumed that all Member States applying price regulation in the energy markets would deliver 30% of consumption of electricity for all households at a reduced rate of 20% less than the average regular price[163]. This level was selected based on the current implementation of various social tariff schemes across Member States, which point towards a reduction in the overall annual bill of 10-30%. However this scheme applies to all households rather than vulnerable households only. These values are for illustrative purposes only and the final amount can be varied depending on the preferences of the Member States implementing the measure.

Under Option 2a the electricity consumption is subsidised for all households for the first 30% and the costs are evenly spread across all consumers.

The impacts on the final consumer bill are presented per Member State in the graphs below – there is very little impact on the final bill of the households due to the fact that the discount is available to all households and is also financed by all households.

However, the average final bill would be lower for households consuming less electricity than the average and higher for households consuming more than the average. Therefore, this option might incentivise households to lower their energy consumption but it could also penalise lower income households which use more electricity than the average due to poor building insulation, lower energy efficient appliances or higher than average people per household.

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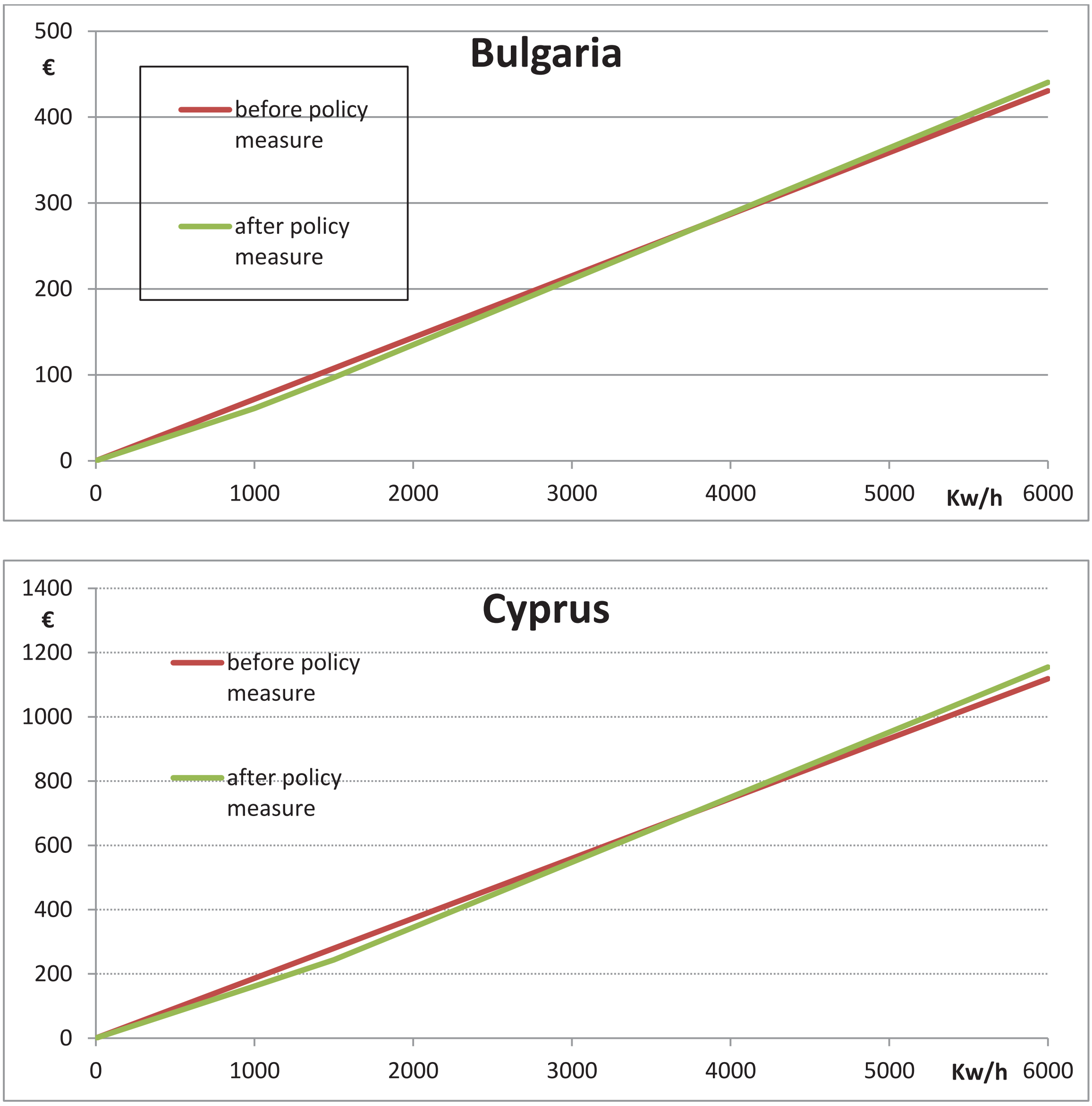
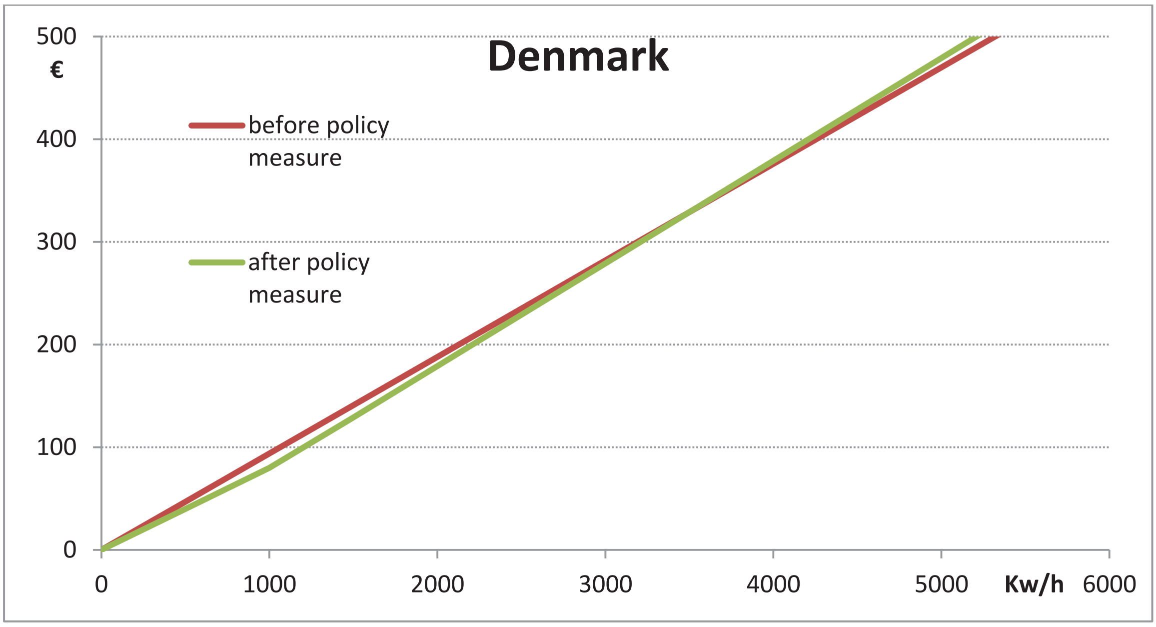
[163] Eurostat, 2014, Average prices excluding all taxes and levies - based on average consumption

Figure 19: Option 2a cross-country comparison of average annual electricity costs per household before and after the introduction of a subsidised amount of electricity

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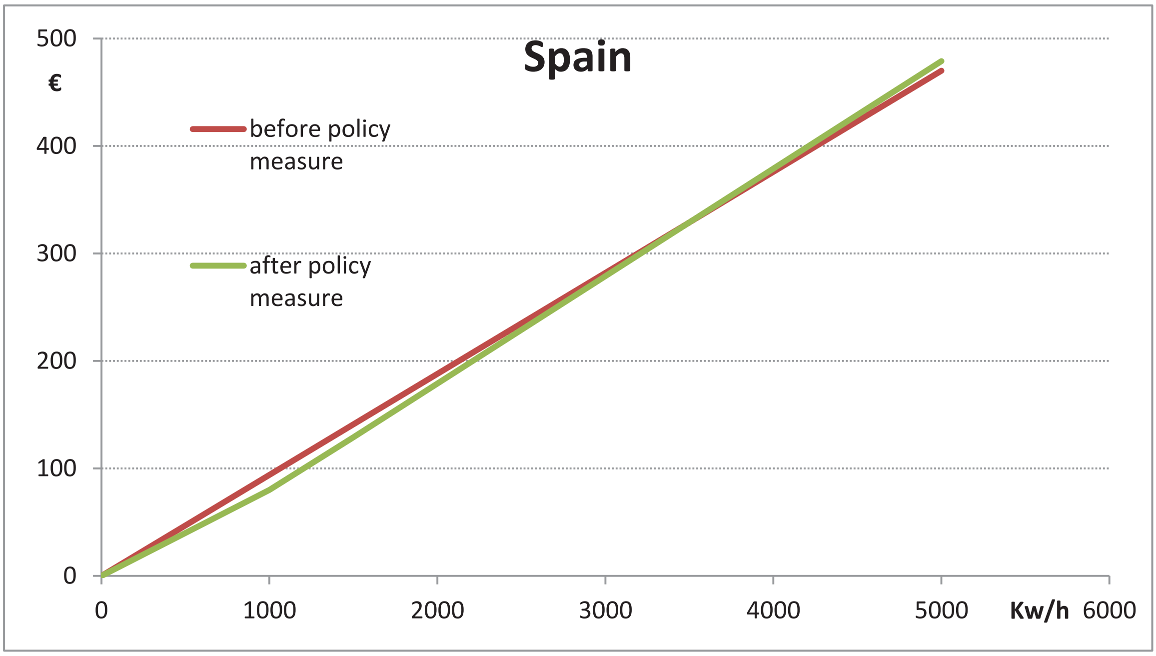
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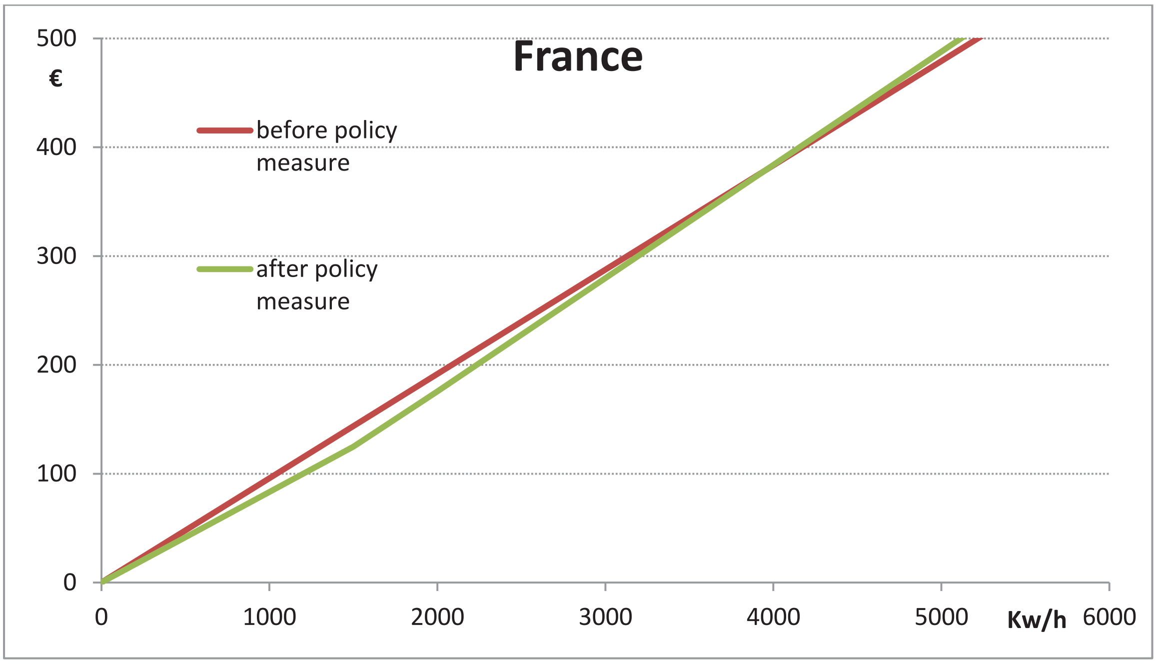
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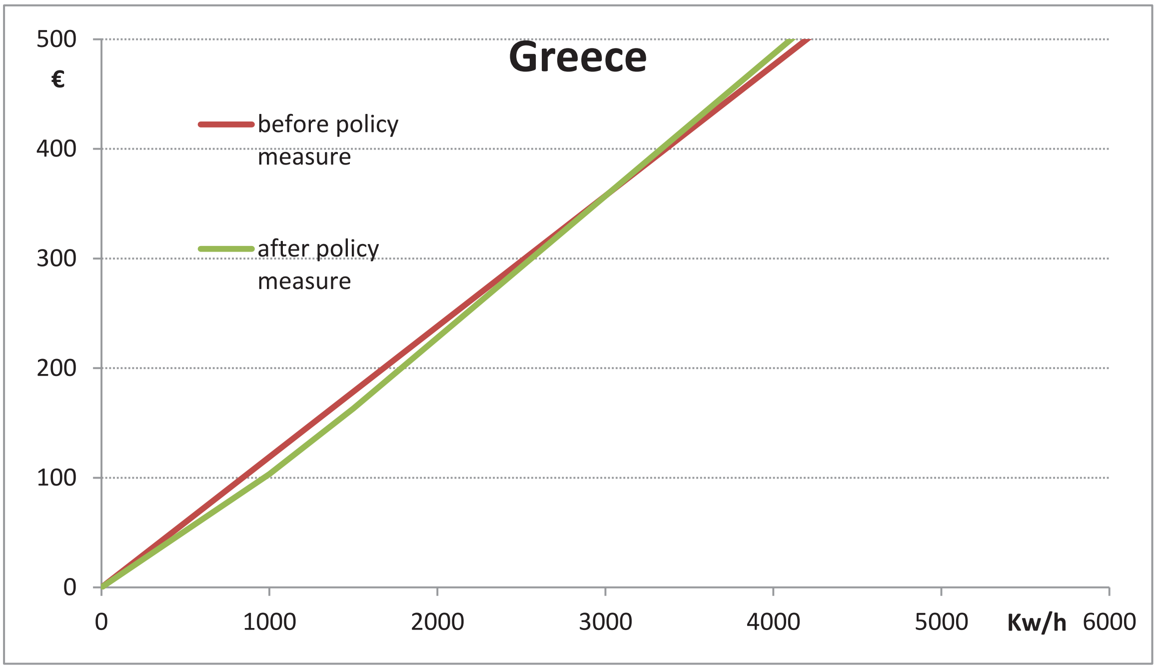
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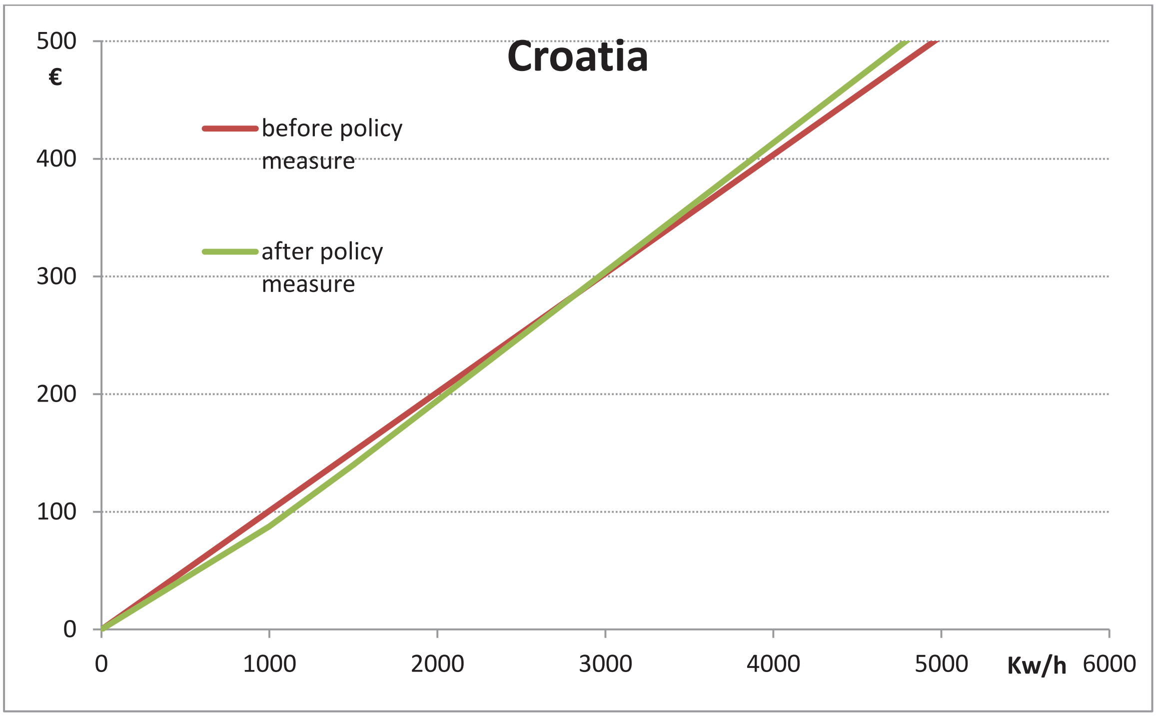
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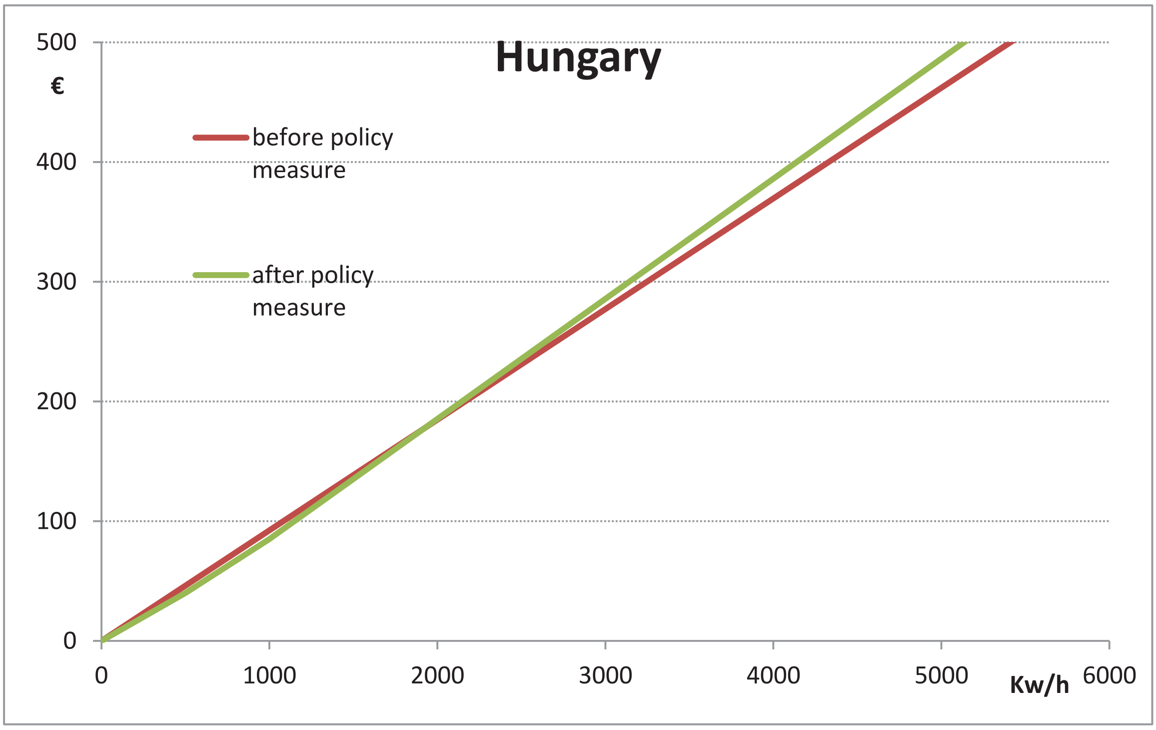
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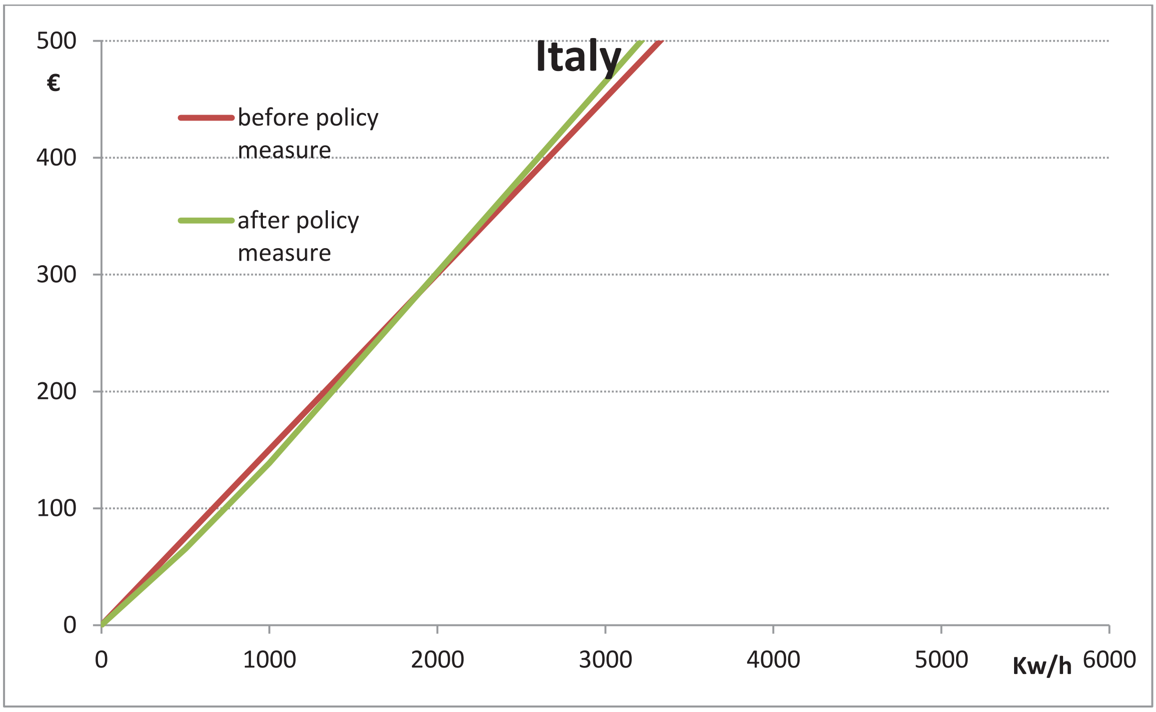
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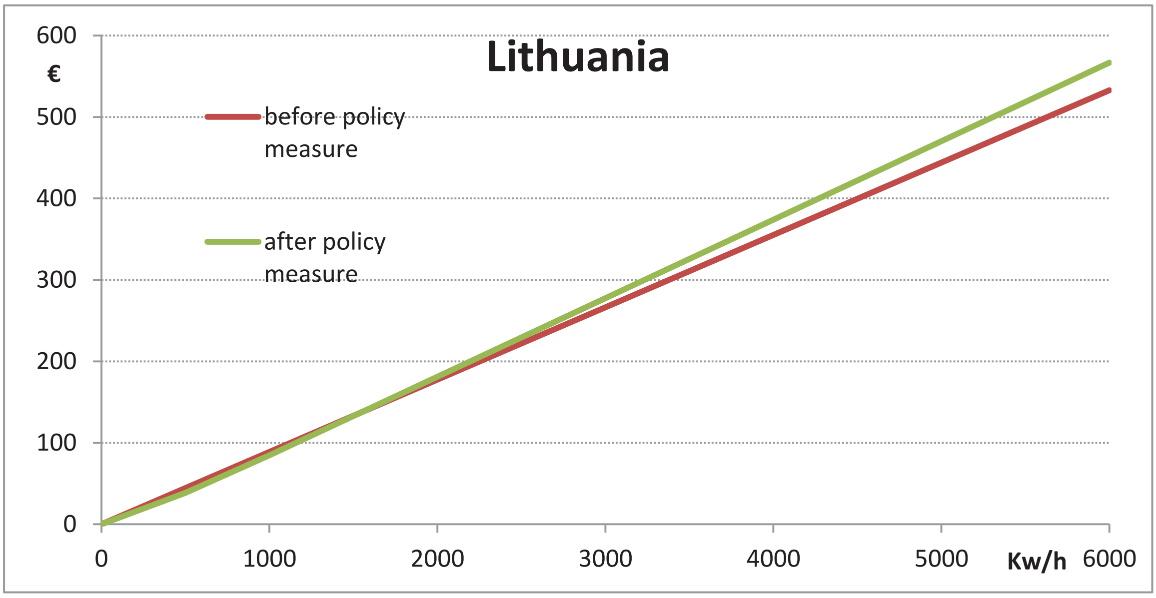
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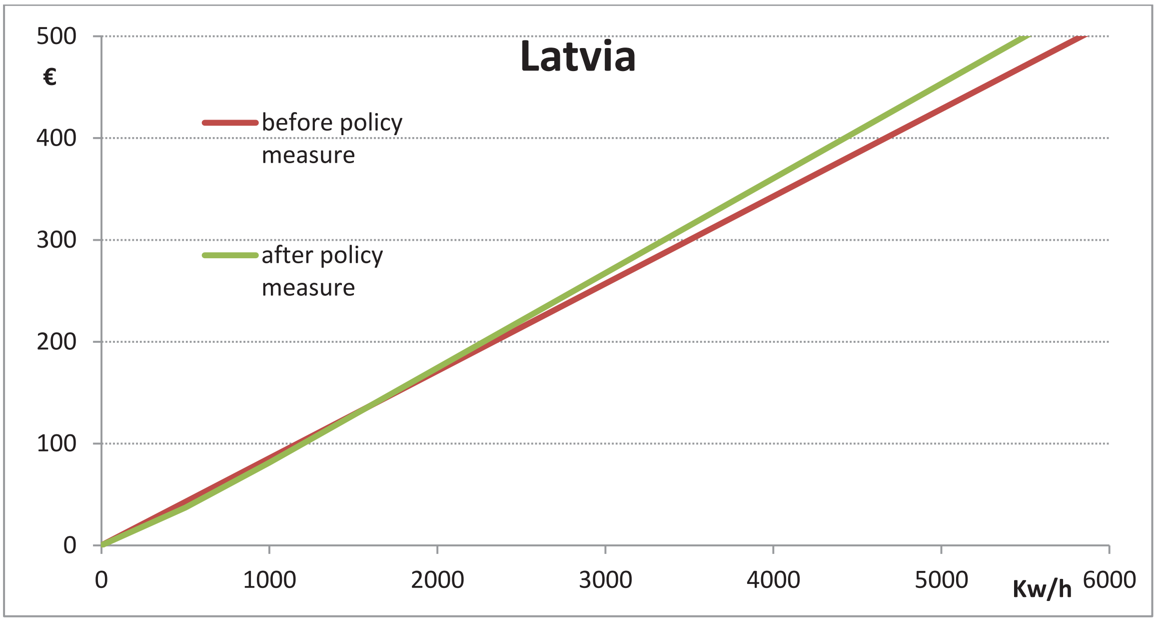
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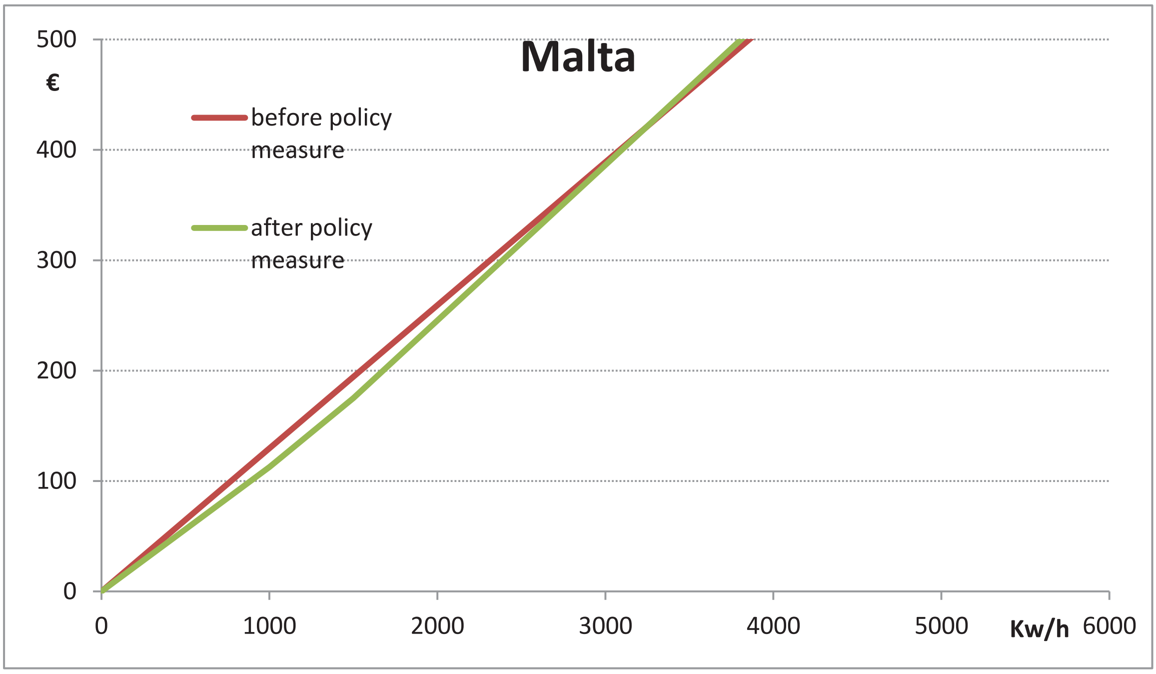
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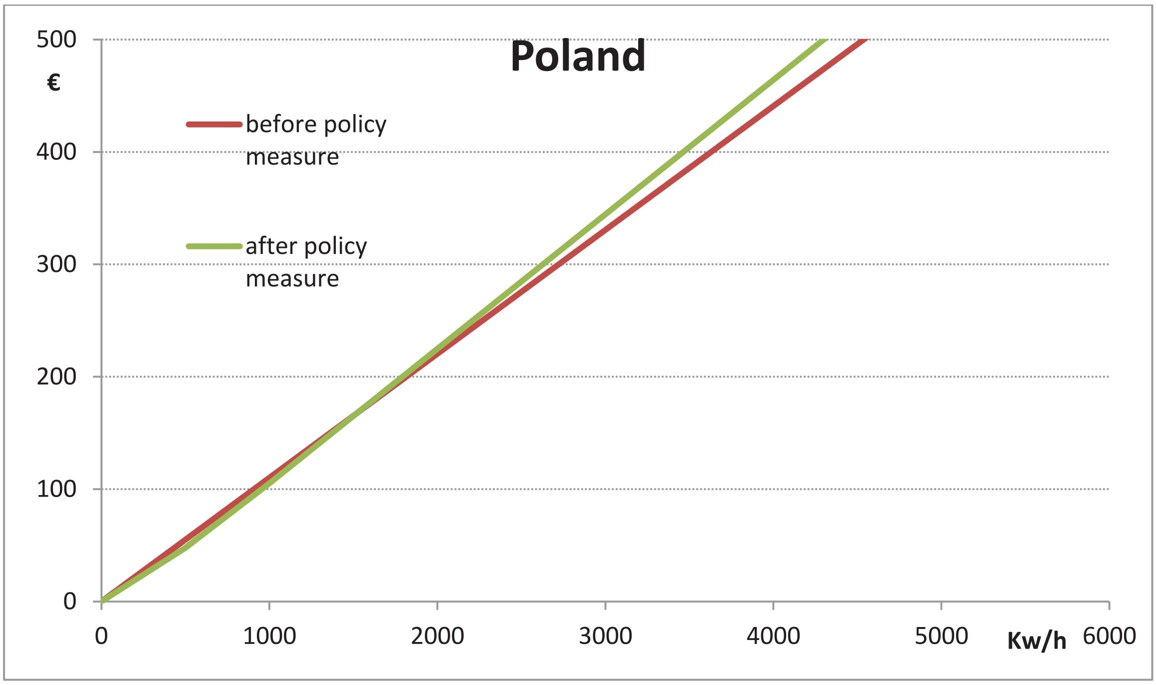
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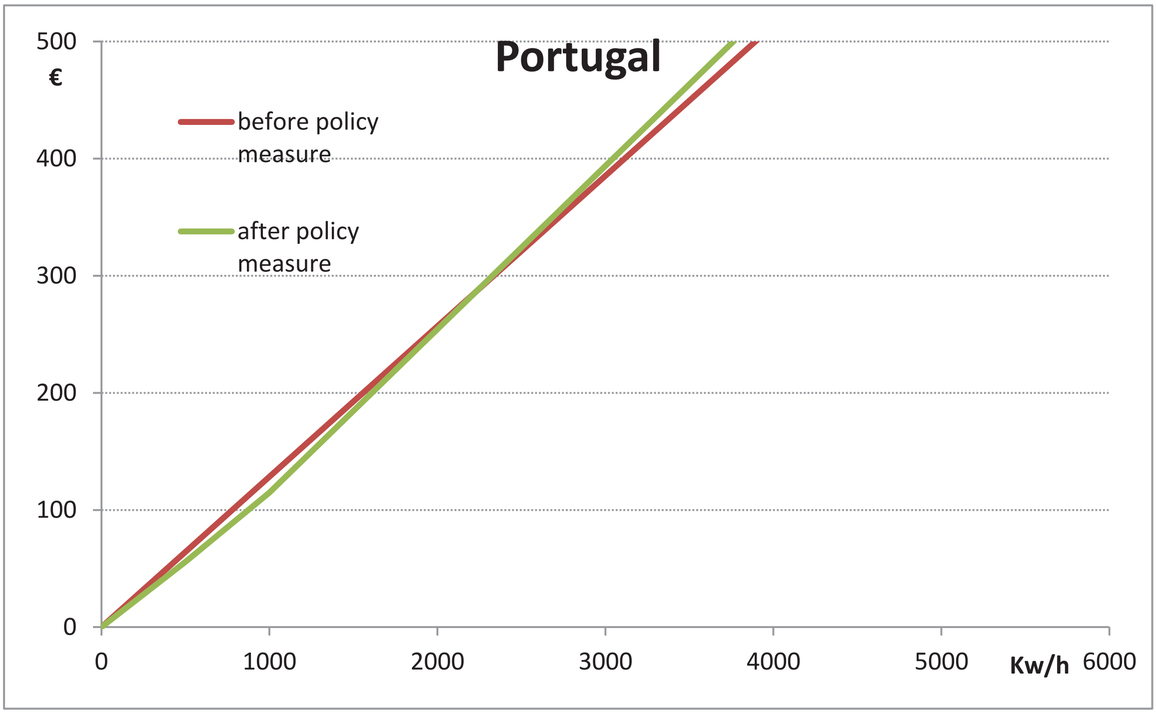
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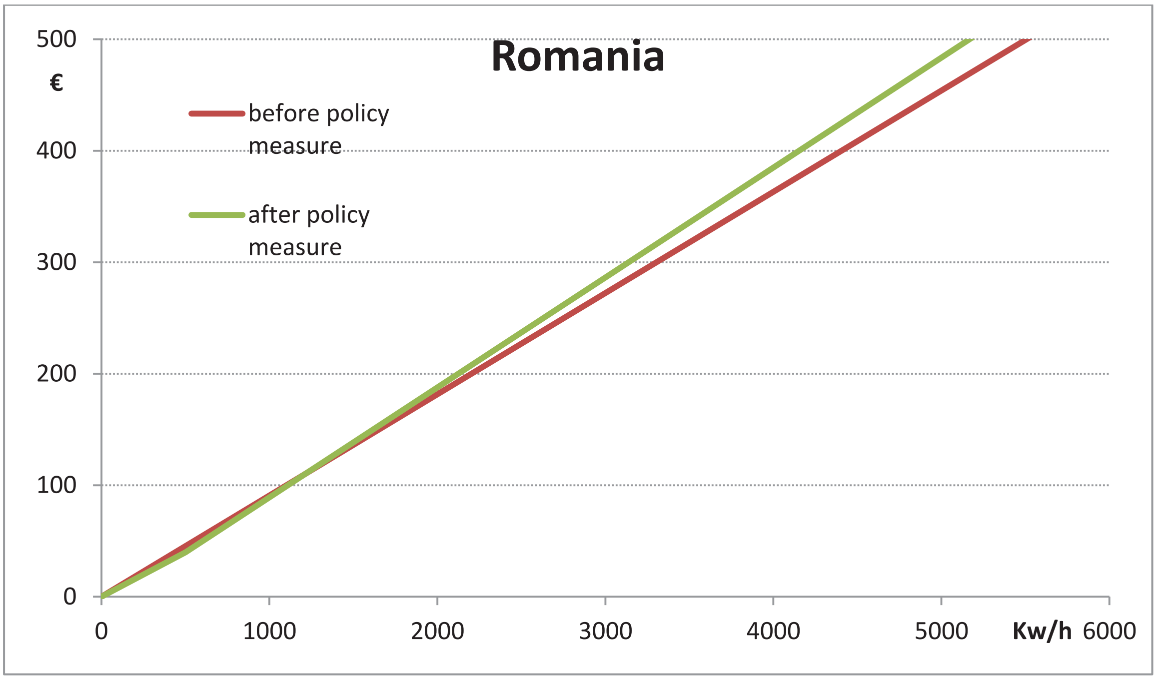
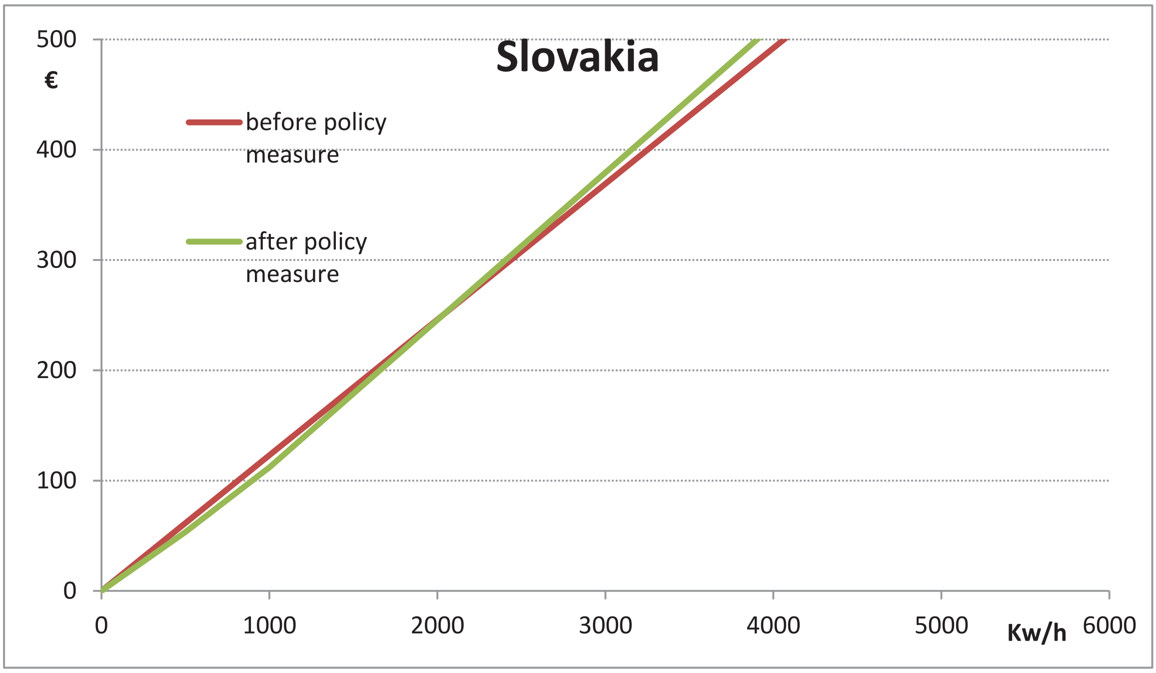




Benefits

In comparison to Option 1 the benefits linked to price deregulation under Option 2a can be expected to be fewer as a greater share of the retail market is covered by regulated prices under Option 2a.

However, in comparison to the current situation, if the consumption threshold beyond which prices are de-regulated was lowered across Member States currently applying price regulation, the net effect of the measure would be beneficial in terms of introducing more competition in the retail energy markets.

Comparison between Option 1 and Option 2a

Option 1 specifically targets the support measures for vulnerable consumers, such that the discounted rate for purchasing electricity is only available to vulnerable consumers. Option 1 also allows greater benefits from the energy market opening in terms of more competition, more consumer choice, better quality of services and more innovation. On the contrary, under Option 2a a lower amount of energy will be subsidised but the subsidy/support will be delivered to all households, regardless of their situation. This means lower support for vulnerable consumers under Option 2a, as shown in Table 8 which indicates the total amounts of electricity subsidised for vulnerable consumers under Option 1 and 2a. At the same time Option 2a delivers lower degree of market opening and therefore lower competition within the market and fewer benefits associated with market competition.

Table 8: Comparison of residential TWh subsidised in comparison to total residential TWh consumed

			Option 1	Option 2a		
	Share of vulnerable households	Total HH consumption	Total electricity subsidised for vulnerable consumers	Total electricity subsidised - vulnerable households	Total electricity subsidised non-vulnerable households	Total electricity subsidised for all households
		TWh	TWh	TWh	TWh	TWh
BG	41%	10.6	4.3	1,3	1,9	3.2
CY	28%	1.4	0.4	0,1	0,3	0.4
DK	3%	10.1	0.3	0,1	2,9	3.0
ES	11%	70.7	7.8	2,4	18,8	21.2
FR	6%	149.4	8.8	2,6	42,2	44.8
GR	33%	17.2	5.6	1,7	3,5	5.2
HR	10%	5.6	0.5	0,2	1,5	1.7
HU	12%	10.4	1.2	0,4	2,8	3.1
IT	18%	64.3	11.6	3,5	15,8	19.3
LT	27%	2.7	0.7	0,2	0,6	0.8
LV	17%	1.7	0.3	0,1	0,4	0.5
MT	22%	0.6	0.1	0,0	0,1	0.2
PL	9%	28.0	2.5	0,8	7,6	8.4
PT	28%	11.9	3.4	1,0	2,6	3.6
RO	12%	11.9	1.5	0,4	3,1	3.6
SK	6%	4.9	0.3	0,1	1,4	1.5
EU-16 Totals	**13%**	**401,5**	**49,4**	**14,8**	**120,4**	**135,2**

Source: INSIGHT_E

While the total subsidised energy is much higher in the case of Option 2a, the amount of energy subsidised for vulnerable customers is lower which indicated a lack of targeting of the measure.

As regards administrative costs for implementing the measures, the blanket approach (lack of identification of a targeted group of beneficiaries) used in Option 2a does not require resources for the identification of vulnerable households. However, these administrative costs linked to the identification of vulnerable consumers can be expected to be minimal as authorities responsible for identifying socially vulnerable groups are already operating in all Member States.

Finally, a comparison of costs between these two options needs to take into account that, in the case of Option 1, costs associated with the implementation of social tariffs would be limited in time due to the temporary nature of the measure, while in the case of Option 2a there is no foreseen end-date for subsidising a specific amount of energy consumption.

Option 2b

Option 2b consists of requiring Member States to progressively phase out below-cost price regulation for households by a deadline specified in new EU legislation

Costs

This option allows price regulation defined at levels that cover the costs incurred by the energy undertakings, therefore no subsidisation is necessary. This option does not involve financing of any new measure therefore a quantitative estimation of costs cannot be performed.

Main costs would be linked to the adoption and implementation of roadmaps foreseeing gradual achievement of cost-reflectiveness of price regulation in the Member States concerned. The main and key challenge for the implementation of this option would be to define methodologies for defining cost coverage of energy prices at EU level in a context where cost structures of market actors are opaque. Moreover, ensuring cost-reflectiveness by regulation would imply considerable regulatory and administrative impact.

Benefits

The main benefits of this option would be to limit the distortive effect of price regulation and tackle tariff deficits.

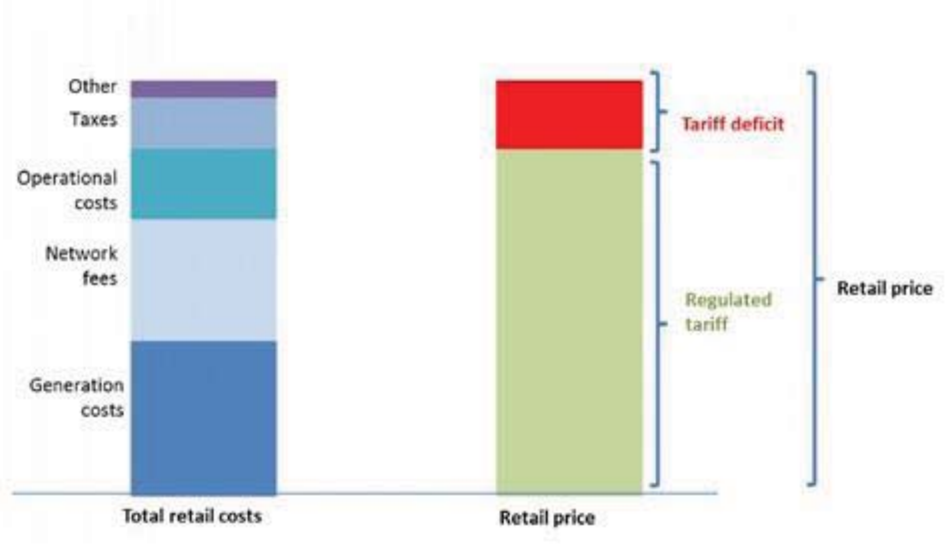
However it is necessary to point to the potential risks associated with energy prices being regulated below costs, such as the accumulation of tariff deficits.

In a study[164] carried out at the request of the European Parliament, a hypothetical case study shows that in a country where the retail market price for electricity is 0.20 euro per kWh for domestic customers and the regulated tariff is set at 0.18 euro per kWh, the tariff deficit would be 0.02 euro per kWh. If there are 15 million domestic customers with an average annual electricity consumption of 3 000 kWh, of whom 80 per cent are supplied at the regulated tariff, the result would be a total tariff deficit of 720 million euro per

[164] "*Cost of Non-Europe in the Single Market for Energy*" (2013) Institute for European Environmental Policy at the request of the European Parliament, available at: http://www.europarl.europa.eu/RegData/etudes/etudes/join/2013/504466/IPOL-JOIN_ET(2013)504466(SUM01)_EN.pdf

year. One may compare the size of the country in this hypothetical illustrative case (15 million domestic customers) with a country of the size of Spain or Poland.

Figure 20: Tariff deficit



Source: European Parliament[165]

Regulated end-user prices reflecting actual costs would ensure remuneration for the suppliers/generators providing them some economic incentives for investment in new and existing generation capacities and in demand reduction measures.

This option could be implemented by progressively increasing the level of regulated prices in countries where they are not cost covering with the objective of achieving cost covering and contestable end user prices. Provided that the level of regulated prices will ensure cost coverage incurred by the suppliers subject to price regulation plus a reasonable profit margin, such measure would stimulate the competition on the retail market by encouraging new entries and allowing existing non-regulated suppliers to gain more market share by proposing better offers to customers. Such incentives would however be limited, directly dependent on the profit margin allowed through the chosen methodology.

It can be expected that benefits linked to enhanced competition on the retail market resulting from the implementation of this option would be more limited compared to Option 1 or 2a mainly due to the lack of limitation of allowed price regulation (as regards the scope of beneficiaries or the regulated amount of energy) which would result in a more important market distortion.

One example of above costs price regulation is through a cost-of-service regulation[166], under which a company is allowed to charge end customers its total incurred costs

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[165] *"The Cost of Non-Europe in the Single Market for Energy" (*2013) European Parliament

[166] "*Regulation of the Power Sector*" (2013) Ignacio J. Pérez-Arriaga

(investment costs plus operation costs), where the investments costs include a fair return on investment.

This example was studied by Pérez-Arriaga[167] who identified that the main advantage of this type of regulation is that it ensures that customers do not overpay and investors are not undercompensated at any given time. However there are also important risks and disadvantages linked to such approach, as shown in the table below.

Cost-of-service regulation	
Pros	**Cons/risks**
Ensures a fair price at any given time (customers do not overpay and investors are not undercompensated) Ensures regulatory stability Guarantees cost recovery (via suitable remuneration), providing a favourable investment climate, reducing capital costs Guarantees high levels of security of supply for electricity customers.	Possible cost inflation due to : - Information asymmetries: utilities have much more precise cost and demand data than the regulator, who needs them in the tariff review process. Information may therefore be manipulated by regulated companies to bring in higher revenues that cannot subsequently be recorded as earnings, but which can be earmarked for certain cost items (such as higher salaries or a larger headcount). - Lack of incentives for efficient management: keeping costs as low as possible (for a given amount and quality of service) calls for some effort from company managers. Under the traditional system of regulation, managers have no incentive to make this effort since, if costs grow, revenues are in principle automatically adjusted to absorb the difference. - Regulator capture: utilities usually have a wealth of resources that can be deployed to influence regulator decisions in their favour. This undue influence on regulatory decisions, called ‘‘regulator capture’’, may be exerted in a variety of ways, including all forms of lobbying, communication campaigns, regulator hire by the regulated utilities and vice versa (so-called revolving doors).

Source: "Regulation of the Power Sector" (2013) Ignacio J. Pérez-Arriaga

It becomes clear that, while this type of price regulation might appear as keeping end customer prices under control while allowing a fair remuneration for energy utilities, it is not exempted from risks of abuse by utilities. Therefore, the objective of protecting customers from possible abuse by utilities in setting the price which is sometimes invoked as justification for maintaining some form of price regulation does not seem to be fully ensured by implementing this option.

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[167] "*Regulation of the Power Sector*" (2013) Ignacio J. Pérez-Arriaga

7.2.6. *Subsidiarity*

Different national approaches to opening of the market for electricity and gas supply to households prevent the emergence of a genuine internal energy market for household customers. More specifically, we observe a wide range of criteria for defining the beneficiaries of price regulation (consumption threshold, in some cases combined with vulnerability criteria).

Under the EU acquis (Art. 14 TFEU, Protocol on SGEI), the Commission has assumed the role of the guardian of both free competition and general interest. The interpretation of the Treaty by the Court of Justice has in some cases allowed a restriction on competition if necessary for the accomplishment of special tasks. Moreover, the adopted and proposed legislation in the field of regulated public services shows how both free competition and restrictions on competition can have a place if required for the accomplishment of special tasks.

The balance between both aspects is subject to the principle of proportionality, implying that the restriction on competition should be no greater than is required to accomplish the special tasks. In defining the proportionality principle, EU legislation can specify the scope of beneficiaries for price regulation (consumption threshold) or the cost coverage condition.

EU action obliging Member States to progressively adopt less restrictive measures to achieve the objectives of general interest justifying price regulation is necessary in order to minimize the negative effect of regulated prices which represent an important barrier to retail competition, including cross-border. The added value of EU action with respect to the deregulation of end-user electricity and gas prices has been highlighted by the European Parliamentary Research Service in a study on "The Cost of Non-Europe in the Single Market for Energy"[168] which considers the possibilities for gains and/or the realisation of a 'public good' through common action at EU level in specific policy areas and sectors. This study identifies regulated end-user prices among the areas that are expected to benefit most from deeper EU integration, where the EU added value is potentially significant.

7.2.7. *Stakeholders' opinions*

Public consultation

The outcome of a public consultation carried out by the European Commission from 22 January 2014 to 17 April 2014 has confirmed that market-based customer prices are an important factor in helping residential customers and SMEs better control their energy consumption and costs (129 out of 237 respondents considered that it was a very important factor while other 66 qualified it as important for the achievement of the said objective).

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[168] http://www.europarl.europa.eu/RegData/etudes/etudes/join/2013/504466/IPOL-JOIN_ET(2013)504466(SUM01)_EN.pdf

Moreover, out of 121 respondents who considered that the level of competition in retail energy markets is too little, 45 recognised regulation of customer prices as one of the underlying drivers.

National Regulatory Authorities

ACER identifies price regulation as one of the barriers to entering retail energy markets, in particular in Member States where regulated prices are set below cost levels, which hampers the development of a competitive retail market. It shows that even in other Member States where end-user prices are set with reference to wholesale prices, which is the preferred approach, they may negatively impact the customers' propensity to switch.

Therefore, ACER recommends that, where justified, regulated prices should be set at levels which avoid stifling the development of a competitive retail market. They must be consistent with the provisions of the Third Package, and should be removed as soon as a sufficient level of retail competition is achieved.

The body representing the EU's national regulatory authorities in Brussels, **CEER** (The Council of European Energy Regulators), identifies as well regulated end-user prices among the barriers to entry for energy suppliers into retail gas and electricity markets across the EU. It shows that in the situation where regulated prices are set below cost, or with a too limited margin to cover the risk of activity, they discourage investments and the emergence of newcomers.

In their reply to the question *"Do you consider regulated end-user prices as a significant barrier to entry for energy suppliers in your MS and have you taken initiatives to remove it?"* included in a questionnaire[169] addressed by CEER to NRAs in 2016, NRAs from countries with price regulation considered them as a significant barrier to entry for alternative suppliers. All Member States, where NRAs consider regulated prices as a significant barrier, are planning to remove them, at least for non-household customers.

In general, NRAs emphasised the need to *"facilitate the phasing out of regulated end user prices, as soon as practicable, whilst ensuring that customers are properly protected where competition is not yet effective"*, as expressed in the conclusions of the ACER / CEER Bridge to 2025.

As part of a roadmap for phasing-out regulated prices, most of the concerned NRAs state that regulated prices should first be aligned with supply costs. They also point out the role of the NRA to define the appropriate methodology and to control end-user prices evolution.

Some NRAs suggest that the final decision for end-user prices withdrawal should depend on the level of competition in the market, which could be assessed by the NRA, like the

[169] *"Benchmarking report on removing barriers to entry for energy suppliers in EU retail energy markets"* (2016) CEER, available at http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab6/C15-RMF-70-03_BR_barriers_to_entry_for_suppliers_1-Apr-2016.pdf

number of market participants and their market share, the transparency of structure and rules of market functioning, a non-discriminatory treatment on the market.
Eventually, some NRAs note the need to protect vulnerable and low income household customers.

Suppliers

EUROGAS[170] supports the distinction between regulated end-user prices and social tariffs. It states that specific, time-limited and appropriate regulated end-user prices may be necessary in circumstances where market forces are not yet in place (in pre-competitive markets notably to ensure headroom for new entrants and to protect customers from market abuse). They should then be generally widely available for customers in those Member States, irrespective of their economic position and should not be set below market price or below cost, to minimise distortions and barriers to entry. Social tariffs where they exist can and should also be organized without market distortions. Member States should not be able to use energy poverty definitions in such a way as to block market development.

In their contribution to the discussions within the workshop on the issue of electricity and gas price (de)regulation organised by the European Commission in the context of the on-going work on the future Electricity Market Design on 3 June 2016, **EURELECTRIC** agreed that regulated prices represent a barrier to entry to new suppliers and that they discourage competition on services.

The European Parliament

In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Customers, the Parliament's **Committee on Industry, Research and Energy (ITRE)**: " Considers that phasing out regulated energy prices for customers should take into account the real level of market competition in the Energy Union Strategy context, which should ensure that customers have access to safe energy prices"

In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Customers, the Parliament's **Committee on the Internal Market and Customer Protection (IMCO)** " Urges the Commission to take concrete action to better link wholesale and retail energy markets, so as to better reflect falling wholesale costs in retail prices and to achieve a gradual phasing-out of regulated prices, and to promote responsible customer behaviour, by encouraging Member States to seek other means to prevent energy poverty; recalls that prices set by the market benefit customers; ".

Consumer Groups

In their contribution to the discussions within the workshop on the issue of electricity and gas price (de)regulation organised by the European Commission in the context of the on-going work on the future Electricity Market Design, **BEUC** has argued that price

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[170] Eurogas press release available at: http://www.eurogas.org/uploads/media/2015-June_-_15PP282__Eurogas_Position_Paper_on_Vulnerable_Customers.pdf

regulation should be a transitional tool before a certain level of competition is achieved on the retail market. In any case, it stated that prices should be fixed at contestable levels to allow alternative suppliers to compete. Moreover, an adequate market design should be the prerequisite for price deregulation.

7.3. Creating a level playing field for access to data

7.3.1. *Summary table*

Objective: Creating a level playing field for access to data.		
Option: 0	Option 1	Option 2
BAU Member States are primarily responsible on deciding roles and responsibilities in data handling.	- Define responsibilities in data handling based on appropriate definitions in the EU legislation. - Define criteria and set principles in order to ensure the impartiality and non-discriminatory behaviour of entities involved in data handling, as well as timely and transparent access to data. - Ensure that Member States implement a standardised data format at national level...	- Impose a specific EU data management model (e.g. an independent central data hub) - Define specific procedures and roles for the operation of such model.
Pro Existing framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro The above measures can be applied independently of the data management model that each Member State has chosen. The measures will increase transparency, guarantee non-discriminatory access and improve competition, while ensuring data protection.	Pro Possible simplification of models across EU and easier enforcement of standardized rules.
Con The current EU framework is too general when it comes to responsibilities and principles. It is not fit for developments which result from the deployment of smart metering systems.	Con	Con High adaptation costs for Member States who have already decided and implementing specific data management models. Such a measure would disproportionally affect those Member States that have chosen a different model without necessarily improving performance. A specific model would not necessarily fit to all Member States, where solutions which take into account local conditions may prove to be more cost-efficient and effective.
Most suitable option(s): Option 1 is the preferred option as it will improve current framework and set principles for transparent and non-discriminatory data access from eligible market parties. This option is expected to have a high net benefit for service providers and consumers and increase competition in the retail market.		

7.3.2. *Description of the baseline*

Legal Framework

Annex I (paragraph 1(h)) of the Electricity Directive set some basic requirements regarding data access from consumers and suppliers, and for the party responsible for data management. It also provides that data should be shared by explicit agreement and free of charge.

Article 41 of the Electricity Directive provides that Member States shall be responsible for setting responsibilities of TSOs, DSOs, suppliers, customers and other market participants with respect to contractual arrangements, commitments to customers, data exchange and settlement rules, data ownership and metering responsibility.

Assessment of current situation

Access to consumption data will support the deployment of distributed energy resources and the development of new flexibility services. This is true not only in relation to flexibility that system operators may use when planning and operating their networks, but also to flexibility that will be used in the wholesale markets for achieving wider system benefits.

Currently different models for the management of data have been developed or are under development across the EU (e.g. data handled by DSO, TSO, or an Independent Data Hub). The activity of handling metering data is closely linked to the traditional metering activity. In the majority of Member States DSOs are responsible for installing and operating the smart metering infrastructure and they are also responsible for collecting consumption data and consequently being involved in the handling process of these data. From a European policy perspective it is important to ensure the impartiality of the entity which handles data and to ensure uniform rules under which data can be shared.

Table 2 presents the responsible entity in each Member State for the metering activity (market regulated/non-regulated), and the responsible entity for the roll-out of smart metering infrastructure, as well as for access to data[171].

[171] *"Benchmarking smart metering deployment in the EU-27 with a focus on electricity"*. COM(2014) 356 final

Table 2: Data handling model in Member States with smart metering systems (implemented or planned)

Wide-scale roll-out (at least 80% of consumers by 2020)	Metering Market	Deployment Strategy	Responsible party - implementation and ownership	Responsible party - access to metering data	Financing of roll-out
Austria	Regulated	Mandatory	DSO	DSO	Metering & Network tariffs
Denmark	Regulated	Mandatory	DSO	Central Hub	Network Tariffs
Estonia	Regulated	Mandatory	DSO	Central Hub	Network Tariffs
Finland	Regulated	Mandatory	DSO	DSO	Network Tariffs
France	Regulated	Mandatory	DSO*	DSO	NA
Greece	Regulated	Mandatory	DSO	DSO	NA
Ireland	Regulated	Mandatory	DSO	DSO	Network Tariffs
Italy	Regulated	Voluntary + Mandatory	DSO	DSO	DSO resources + network tariffs
Luxembourg	Regulated	Mandatory	DSO	DSO	Network Tariffs
Malta	Regulated	Voluntary	DSO	DSO	Network Tariffs
Netherlands	Regulated	Mandatory w/ opt-out	DSO	DSO	Network Tariffs
Poland	Regulated	Mandatory	DSO	Central Hub	Network Tariffs
Romania	Regulated	Mandatory	DSO	DSO	Network Tariffs
Spain	Regulated	Mandatory	DSO	DSO	Network Tariffs + SM rental
Sweden	Regulated	Voluntary	DSO	DSO	DSO resources + network tariffs
United Kingdom - GB	Competitive	Mandatory	Supplier	Central Hub	Funded by suppliers

Source: COM(2014) 356 final

According to the above data in the majority of Member States the DSO is the responsible party for metering activity and smart meters, as well as for data access. However, regarding data access more recent information indicates that some Member States such as Finland and Sweden are planning a central data hub under the responsibility of the TSO.

In general it is observed, that in countries with a high number of DSOs (e.g. SE, FI) it seems to be more effective to introduce a central hub which will collect information from several DSOs and provide access to these data to third parties. In such cases it is expected that transparency and efficiency in the market will increase, while data will be easily available to retailers and consumers.

However, different data handling models do not exclude responsibility and involvement of DSOs, in most of the cases they are responsible for smart meters and participate in the data handling process. This means that even if they are not assuming a central role in data handling (e.g. the case of France or Italy), they will collect consumption data and communicate these data to a central hub.

Requirements of Article 1(h) of Annex I have been subject to formal actions against several Member States.

7.3.3. *Deficiencies of the current legislation*

The Evaluation illustrates how one of the main objectives of the Electricity Directive was to improve competition through better regulation, unbundling and reducing asymmetric information. In general, unbundling measures contribute to the contestability of the retail market and thus facilitate market entry by third party suppliers.

The implementation of smart metering systems in 17 Member States will generate more granular consumption data and new business opportunities in the retail market. Data management models for handling those data are accompanied by procedures which facilitate the retail market and improve processes such as switching, billing, settlements etc.

The existing provisions of the Electricity Directive provide a general framework under which each Member State can decide its data management model and procedures of data handling. This framework however needs to be enhanced and updated in terms for instance of eligible market parties who should be allowed to access consumers' data, authorization of parties which handle data, simple procedures and interoperable data format. Indeed, Section 7.3.6 and Annex IX of the Evaluation show that the current legislation was not designed to address currently known challenges in managing large, commercially valuable consumption data flows.

7.3.4. *Presentation of the options*

Under **Option 0** (BAU) Member States are responsible to develop their own data handling model in line with rules of the Third Package and the related data protection legislation. Member States are responsible for developing their own data handling models in line with rules of the Third Package and the related data protection legislation.

A stronger enforcement and/or voluntary cooperation (Option 0+) has not been considered as the existing EU framework provide only minimum requirements which need to be updated in line with the developments in the retail market and the introduction of smart metering systems, while voluntary cooperation would only deliver a set of best practices that Member States could share, but it would not be adequate for setting the necessary principle for a transparent and non-discriminatory exchange of data.

Under **Option 1** Member States will continue to be responsible for the development of the data management model; however, more explicit requirements will be introduced regarding responsibilities in data handling based on appropriate definitions and principles. Also, criteria and measures will be introduced to ensure the impartiality and non-discriminatory behaviour of entities involved in data handling, as well as timely and transparent access to data. Member States will also have to implement a standardised data format in order to simplify retail market procedures and enhance competition. Measures under this option will also ensure data protection in line with the requirements of Regulation (EU) 2016/679 on the protection of personal data and Recommendation 2014/724/EU on the Data Protection Impact Assessment Template for smart grids and smart metering systems.

Under **Option 2** each Member State will have to implement a specific data management model and procedures described in EU legislation.

7.3.5. _Comparison of the options_

a. *The extent to which they would achieve the objectives (effectiveness);*

The main objective is to ensure that data handling models support equal data access and facilitate retail market competition.

Option 0 would mean no further measures from the existing framework set in the Electricity Directive. Member States would be practically completely responsible for setting the general framework and the detailed regulation on data management models, access rules and principles, roles and responsibilities of market actors etc.

Data access is highly important for supporting new services and for facilitating competition, especially where smart metering systems exist. Option 0 would not guarantee that national frameworks will accommodate all necessary elements in order for instance to allow data access to a minimum of service providers besides suppliers.

Moreover, the current framework does not include any measures in order to avoid privileged access to information from service providers which are affiliated to operators which collect and store data (e.g. DSOs).

Option 1 seeks to address deficiencies of Option 0 by enhancing the existing framework and set minimum requirements in terms of eligible market parties which should have access to data, specific principles, and ensuring consumers' privacy. Moreover, this option will set some minimum safeguards in order to avoid privileged access to data of commercial value. The level of effectiveness of this option will depend on the specific implementation in each Member State and the detailed national rules, as measures under this option will set the basic EU framework.

Option 2 is considered to be less effective compared with the other two options as it will entail full harmonisation of data management models and rules across EU Member States. As in many Member States (e.g. UK, IT, FR, FI, NL, AT etc.) the data management models have been already implemented or planned, the imposition of a different model (e.g. independent data hub), would entail a restructuring of the existing models.

The above policy options were developed in the context of the Digital Single Market[172] and the Energy Union which include the strong and efficient protection of fundamental rights in a developing digital environment. One of the objectives should be to ensure widespread access and use of digital technologies while at the same time guaranteeing a high level of the right to private life and to the protection of personal data as enshrined in Articles 7 and 8 of the Charter of Fundamental Rights of the EU.

[172] In the context of the Digital Single Market the Commission will propose a European free flow of data initiative with the aim to promote free movement of data in the European Union. The initiative will tackle restrictions to data location and access to encourage innovation. The Commission will also launch a European Cloud initiative, covering certification, switching of cloud service providers and a research cloud (https://ec.europa.eu/digital-single-market/en/economy-society-digital-single-market).

The policy options proposed (from compliance with data protection legislation and the Third Package - Option 0; to further introduction of specific requirements on data handling responsibilities based on principles of transparency and non-discrimination - Option 1; and implementation of a specific data management model to be described in EU legislation - Option 2) seek to ensure the impartiality of the entity which handles data and to ensure uniform rules under which data can be shared. Access to a consumer's metering or billing details can only happen when authorised by that consumer and under the condition that the personal data protection and privacy are guaranteed.

The policy options are fully aligned and further substantiate the fundamental rights to privacy and protection of personal data of Articles 7 and 8 of the Charter of Fundamental Rights of the EU, as well as with the General Data Protection Regulation (EU Regulation 2016/679 modifying Directive 95/46/EC) and with Commission Recommendation 2014/724/EC on the Data Protection Impact Assessment Template for Smart Grid and Smart Metering Environments.

b. Key economic impacts and benefit/cost ratio, cost-effectiveness (efficiency) & Economic impacts

Option 1 is expected to yield higher net benefits in comparison with option 0, as it will set principles for an open and more competitive retail market. Moreover, specific procedures of the market such as switching are expected to improve with stricter requirements on the data format.

An overall positive effect on the energy market can be expected. Active and well-aware consumers are more likely to make informed decisions, from choosing their energy supplier to consumption decisions. More consumers might switch their supplier, which will foster competition in the retail market. Active consumers might also consider third party services such as applications to reduce or optimise their energy consumption, which would amplify the market for third party activities. Different initiatives and business models could simplify the interaction between consumers and third parties, and therewith further increase the market potential of third party services[173].

Moreover, direct feedback for example on real time consumption data and energy prices, could have a substantial impact on energy savings. Evidence from Ireland and the UK show that energy savings can reach up to 2.5% and 8.8% in peak hours[174].

[173] Like for instance the Green Button initiative in US where consumers can easily give access to their consumption data to third parties who automatically receive a standardized data-package for that consumer; the initiative positively affected the overall business case of third parties (*"Green Button: One Year Later*" (2012) IEE Edison Foundation). Another example of such initiative is the Midata initiative in UK (http://www.gocompare.com/money/midata/) which concerns energy and other sectors; as energy firms are increasingly taking on board the need to provide customers with downloadable data to better understand their gas and electricity usage, Midata initiative aims to further encourage this practice across all energy suppliers and to make it easier to upload this data to comparison sites.

[174] Intelligent Energy Europe (2012): "*European Smart Metering Landscape Report 2012"*; Ofgem (2011): "*Energy Demand Research Project: Final Analysis"* (study conducted by AECOM for Ofgem).

A main benefit of ensuring interoperability between different data systems is the easy access to new markets for commercial actors such as energy suppliers or aggregators. Ensuring for instance uniform formats for consumption data reduces entry barriers for commercial actors seeking to establish in other Member States. This could enhance competition in the supplier and aggregator market. Ensuring interoperability would imply agreeing to a common standard at national level, which would induce some costs such as administrative costs for defining and concurring on the new format, especially to data administrators (DSOs or data hubs) who will have to adapt their system to a new common format. Depending on the case such costs might be significant, as a number of existing data handling systems and the involved entities would have to adjust to the new standards (suppliers, DSOs, third parties, data administrators). However, it is expected that on an aggregated level these costs will not exceed benefits.

The implementation of **Option 2** would entail high administrative costs. Determining a mandatory data handling model will imply administrative costs of defining and designing such a model, and more importantly high sunk costs for existing data handling models and additional costs for establishing a new one, both in terms of personnel costs and IT infrastructure. Designing and building a new data handling model is a complex procedure and may well take several years of planning and implementation. In Denmark, the central data hub took more than 4 years to design and develop in its simple form, and 7 years in its enhanced form, and is estimated to a cost of approximately 165 million euros, where approximately 65 million euros accrued to the data hub administrator (the TSO), and around 100 million euros accrued to DSOs and energy suppliers. Therefore, the costs of redesigning already implemented data handling models across the EU are therefore likely to be substantial.

c. Simplification and/or administrative impact for companies and consumers

Option 2 for data management would result in high administrative costs affecting existing structures as well as possibly energy companies and consumers.

d. Impacts on public administrations

Impacts on public administration are summarized in Section 7 below.

e. Trade-offs and synergies associated with each option with other foreseen measures

Options 1 and 2 for data management are clearly also associated with demand response and smart metering. Smart meters will provide granular data which should be accessible from service providers for settlement or support of services. A well-functioning data management model is therefore crucial for the provision of demand response services.

f. Likely uncertainty in the key findings and conclusions

There is a medium risk associated with the uncertainty of the assessment of costs and benefits of the presented options. However, it is considered that this risk cannot influence the decision on the preferred option as there is a high differentiation among the presented options in terms of qualitative and quantitative characteristics.

g. Which Option is preferred and why

Option 1 is the preferred option as it will improve current framework and set principles for transparent and non-discriminatory data access from eligible market parties. This option is expected to have a high net benefit for service providers and consumers and increase competition in the retail market.

Box 1: Impacts on different groups of consumers

The benefits of the measures contained in the preferred option (Option 1), described in detail in the preceding pages, accrue evenly to all consumers. The measures can therefore be considered neutral in nature i.e. they do not redistribute surplus between higher- and lower-income ratepayers.

7.3.6. *Subsidiarity*

The EU has a shared competence with Member States in the field of energy pursuant to Article 4(1) of the Treaty on the Functioning of the European Union (TFEU). In line with Article 194 of the TFEU, the EU is competent to establish measures to ensure the functioning of the energy market, ensure security of supply and promote energy efficiency.

Uncoordinated, fragmented national policies in the electricity sector may have direct negative effects on neighbouring Member States, and distort the internal market. EU action therefore has significant added value by ensuring a coherent approach in all Member States.

An effective EU framework for data management which puts in place rules and principles will give to electricity consumers more choices, better access to information and will facilitate competition in the electricity market. Moreover, through effective data management models and efficient procedures consumers will have access to more energy service providers and actively participate in the electricity market. Active participation of consumers and facilitation of demand response and energy efficiency service will contribute to the completion of the internal energy market and support security of supply.

Envisaged measures do not aim to alter the structure of existing or planned national data management models, but to set requirements which will enhance fundamental consumer rights and support a competitive internal energy market.

7.3.7. *Stakeholders' opinions*

3.2.7.1. *Results of the consultation on the new Energy Market Design*

According to the results of the public consultation on a new Energy Market Design[175] the respondents view active distribution system operation, neutral market facilitation and data hub management as possible functions for DSOs. Some stakeholders pointed at a potential conflict of interests for DSOs in their new role in case they are also active in the supply business and emphasized that the neutrality of DSOs should be ensured. A large number of the stakeholders stressed the importance of data protection and privacy, and

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[175] https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

consumer's ownership of data. Furthermore, a high number of respondents stressed the need of specific rules regarding access to data.

Governance rules for DSOs and Models of data handling

Question: *"How should governance rules for distribution system operators and access to metering data be adapted (data handling and ensuring data privacy etc.) in light of market and technological developments? Are additional provisions on management of and access by the relevant parties (end-customers, distribution system operators, transmission system operators, suppliers, third party service providers and regulators) to the metering data required?"*

Summary of findings:

The majority of stakeholders consider access to data by consumers and relevant third parties under specific rules as an important element for the development of an open and competitive retail market. Moreover, it is crucial to ensure data privacy and ownership of data by consumers.

Regarding the data handling models, regulators and the majority of stakeholders from the electricity industry believe that DSOs should act as neutral market facilitator. Some stakeholders from the electricity industry suggest that the DSOs should undertake the role of the data hub, providing an effective way to govern the data generated by smart meters. On the other hand, IFIEC and few other stakeholders do not see favourably the role of DSOs as market facilitator, the involvement of a third party is perceived to better support neutrality and a level playing field.

National governments are divided on the best suitable model for data access and data handling, around half of them advocate as the most favourable solution central data hubs. Most of the Member States consider that the role of DSO and the model for data handling should be best decided at national level.

Member States:

Given the central role of DSOs in metering and handling of data, Member States point out the necessity for neutrality and independence of the DSO vis-à-vis other energy stakeholders, while they consider that coordination between DSOs and TSOs should be enhanced. Data need to be accessible in real-time or close to real-time for consumers and relevant third parties, while data security and privacy is one of the most important aspects for the acceptance of smart meters and the successful roll-out.

Some Member States promote central data hubs to collect and handle data (e.g. Denmark, Estonia, Finland, Germany, Slovakia, and Sweden).

Some Member States (Czech Republic, France, Netherlands, and Slovakia) believe that due to different local conditions in terms of available technologies and national regulatory frameworks, detailed arrangements regarding data handling should be defined at member State level through national legislation, and no further legislation is required at EU level regarding the role of DSOs and the responsibilities for data handling.

On the other hand the Danish government considers that EU regulation should more specifically define a minimum level of privacy and issues such as consumers' control over their own data and non-discriminatory access to data by market players, while harmonising the roles of market players and the kind of data they have access to. The

Finnish government also calls for a clarification of the role of DSOs in the operation of storage facilities and questions whether there is a need to revise unbundling rules.

Regulators:

Regulators stress the importance of neutrality in the role of the DSOs as market facilitators. To achieve this will require to:

- Set out exactly what a neutral market facilitator entails;
- When a DSO should be involved in an activity and when it should not;
- NRAs to provide careful governance, with a focus on driving a convergent approach across Europe.

Regulators consider that consumers must be guaranteed the ownership and control of their data. The DSOs, or other data handlers, must ensure the protection of consumers' data.

Electricity consumers:

The majority of stakeholders (BEUC, CEFIC, CEPI) agree that consumers should have access to real time information, historical information, accurate billing and easy switch of provider. Some of them (CEFIC, EURACOAL) believe that the DSOs should play a central role in providing end-users with the necessary information. All electricity consumer stakeholders agree that data protection must be assured.

IFIEC considers that DSOs should not play the role of market facilitator, the involvement of a third party is perceived to better support neutrality and a level playing field. Moreover, coordination of TSOs and DSOs and potentially extended role of DSOs with respect to congestion management, forecasting, balancing, etc. would require a separate regulatory framework. However, IFIEC express concerns that some smaller DSOs might be overstrained by this. Extended roles for DSO should be in the interest of consumers and only be implemented when it is economically efficient.

EUROCHAMBERS believes that due to different regional and local conditions a one size fits all approach for governance rules for distribution system operators is not appropriate. The EU could support Member States by developing guidelines (e.g. on grid infrastructures and incentive systems).

Energy industry:

Most stakeholders (CEDEC, EDSO, ESMIG, ETP, EUROBAT, EWEA, GEODE) believe that the role of DSOs should focus on active grid management and neutral market facilitation. Some respondents state that the current regulatory framework prevents DSOs from taking on some roles, such as procurer of system flexibility services and to procure balancing services from third parties, and such barriers should be eliminated.

All stakeholders agree that the provision of data management services should be carried out in a neutral and non-discriminatory manner with all appropriate protections for data security, data privacy and the right of the consumers to control third party access to their data. On this regard, GEODE highlights the need to have a clear distinction between personal data (which belongs to the customer) and non-personal data which should be provided to any relevant party who requests it, on a non-discriminatory basis.

According to Eurelectric, EWEA, ETP and GEODE, DSOs operating as data hub could provide an effective way to govern the data generated by smart meters.

463 Creating a level playing field for access to data

Eureletric believes that the need for guaranteeing security of information and preventing cyber-attacks could also be better ensured when there is only one entity in charge of managing information flow. Mindful of the different unbundling situations in place in the EU, DSOs should be responsible for data handling up to the metering point in a fully unbundled context. Moreover, regulatory authorities should make sure that data management beyond the meter takes place in a condition that ensures customer privacy and it should be up to the consumers whether to receive their data through an intermediary (a market party) or retrieve it from a web platform linked to the data hub. Costs connected with data management should be recovered via network tariffs.

According to RGI, for privacy reasons most data should remain in the meter itself. Data should be stored in and regulated by a public server in an aggregated and formatted way only dealing with the strictly necessary information. TSOs should have access to relevant data, reflecting the actual energy portfolio and installed capacity per source at any given time.

Also SEDC envisages that DSOs should be neutral market facilitators where unbundling is fully implemented. However, in this scenario DSOs should not be active in markets such as for demand response, as this would undermine their neutrality.

In relation to a possible EU intervention on the topic, GEODE suggests that Commission should lay down generic principles rather than specific provisions, taking into account that different Member States implement different models on the treatment of smart metering data.

3.2.7.2. *Public consultation on the Retail Energy Market*

According to the results of the 2014 public consultation on the Retail Energy Market[176] the majority of the respondents consider that DSOs should carry out tasks such as data management, balancing of the local grid, including distributed generation and demand response, and connection of new generation/capacity (e.g. solar panels).

81% of the respondents agreed that allowing other parties to have access to consumption data in an appropriate and secure manner, subject to the consumer's explicit agreement, is a key enabler for the development of new energy services for consumers.

3.2.7.3. *Electricity Regulatory Forum - European Parliament*

Relevant conclusions of the 31st EU Electricity Regulatory Forum:

- *"The Forum supports the cooperation of TSOs and DSOs on data management, considering it an important step in finding common solutions to system operation and system planning. It acknowledges the need to identify at EU-level a set of common principles, roles, responsibilities and tasks concerning data management, which will enable the development of new services and the active participation of consumers in the future energy system while ensuring data protection and leaving room for implementation at national level."*

[176] https://ec.europa.eu/energy/en/consultations/consultation-retail-energy-market

European Parliament resolution of 26 May 2016 on delivering a new deal for energy consumers (2015/2323(INI)):

"29. Believes that consumers should have easy and timely access to their consumption data and related costs, to help them make informed decisions; notes that only 16 Member States have committed to a large-scale roll-out of smart meters by 2020; believes that where smart meters are rolled out Member States should ensure a solid legal framework to guarantee an end to unjustified back-billing and a rollout that is efficient and affordable for all consumers, particularly for energy-poor consumers; insists that the benefits from smart meters should be shared on a fair basis between grid operators and users;"

"33. Underlines that the collection, processing and storage of citizens' energy-related data should be managed by entities managing data access in a non-discriminatory manner and should comply with the existing EU privacy and data protection framework which lays down that consumers should always remain in control of their personal data and that these should only be provided to third parties with the consumers' explicit consent; considers, in addition, that citizens should be able to exercise their rights to correct and erase personal data;"

7.4. Facilitating supplier switching

7.4.1. *Summary table*

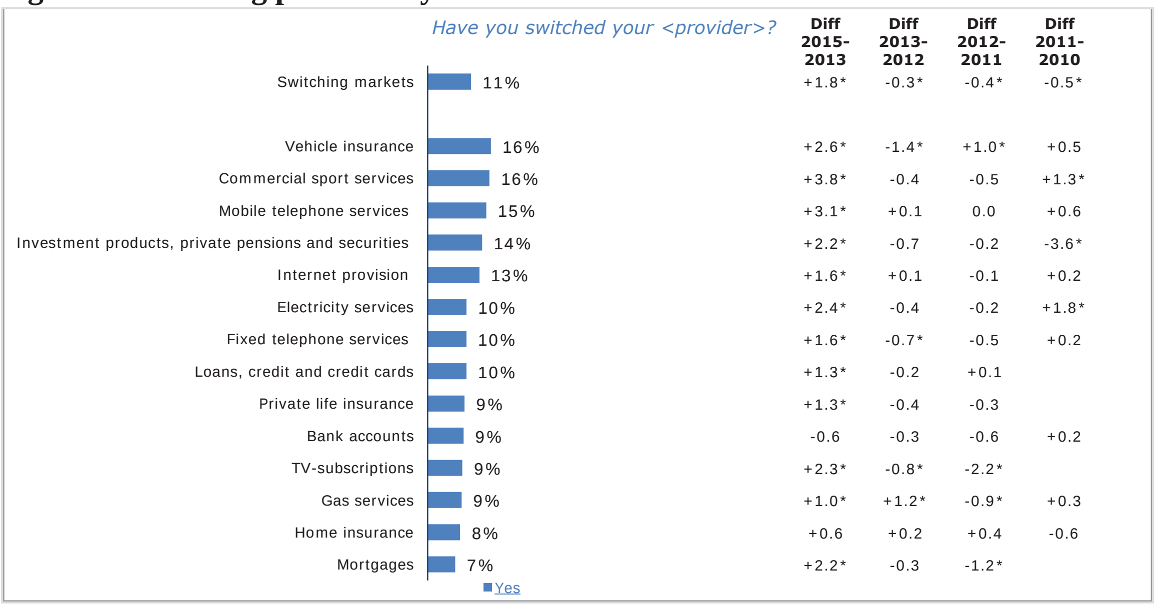
Objective: Facilitating supplier switching by limiting the scope of switching and exit fees, and making them more visible and easier to understand in the event that they are used.			
Option 0	**Option 0+**	**Option 1**	**Option 2**
BAU/Stronger enforcement	Stronger enforcement, following the clarification of certain concrete requirements in the current legislation through an interpretative note.	Legislation to define and outlaw all fees to EU household consumers associated with switching suppliers, apart from: 1) exit fees for fixed-term supply contracts; 2) fees associated with energy efficiency or other bundled energy services or investments. For both exceptions, exit fees must be cost-reflective.	Legislation to define and outlaw all fees to EU household consumers associated with switching suppliers.
Pros: - Evidence may suggest a degree of non-enforcement of existing legislation by national authorities. - No new legislative intervention necessary.	Pros: - Non-enforcement may be due to complex existing legislation. - No new legislative intervention necessary.	Pros: - Considerably reduces the prevalence of fees associated with switching suppliers, and hence financial/psychological barriers to switching.	Pros: - Completely eliminates one financial/psychological barrier to switching. - Simple measure removes doubt amongst consumers. - The clearest, most enforceable requirement without exceptions.
Cons: - Continued ambiguity in existing legislation may impede enforcement. - The vast majority of switching-related fees faced by consumers are permitted under current EU legislation.	Cons: - The vast majority of switching-related fees faced by consumers are permitted under current EU legislation. - Certain Member States might ignore the interpretative note.	Cons: - Marginally reduces the range of contracts available to consumers, thereby limiting innovation. - An element of interpretation remains around exceptions to the ban on fees associated with switching suppliers.	Cons: - Would further restrict innovation and consumer choice, notably regarding financing options for beneficial investments in energy equipment as part of innovative supply products e.g. self-generation, energy efficiency, etc. - Impedes the EU's decarbonisation objectives, albeit marginally.
Most suitable option(s): Option 1 is the preferred option, as it represents the most favourable balance between probable benefits and costs.			

7.4.2. *Description of the baseline*

The evidence presented in this annex draws extensively on survey data, as well as data from a mystery shopping exercise. The aim of the mystery shopping exercise was to replicate, as closely as possible, real consumers' experiences across 10 Member States[177] selected to cover North, West, South and East Europe countries. A total of 4,000 evaluations were completed between 11 December 2014 and 18 March 2015[178]. Whilst data from the mystery shopping exercise is non-exhaustive, the methodology enables the controlled sampling of a very large topic area[179], as well as providing insights that would not be apparent in a desktop evaluation of legislation and contractual terms. Using a behavioural research approach rather than a traditional survey allowed us to identify what people actually do, rather than what they say they do.

Switching rates[180] for energy – a proxy for consumer engagement in the market – vary considerably between Member States (0-15%), with electricity and gas comparing unfavourably with many other consumer sectors such as vehicle insurance and mobile telephony.

Figure 1: Switching provider by market - EU28



Source: Market Monitoring Survey, 2015

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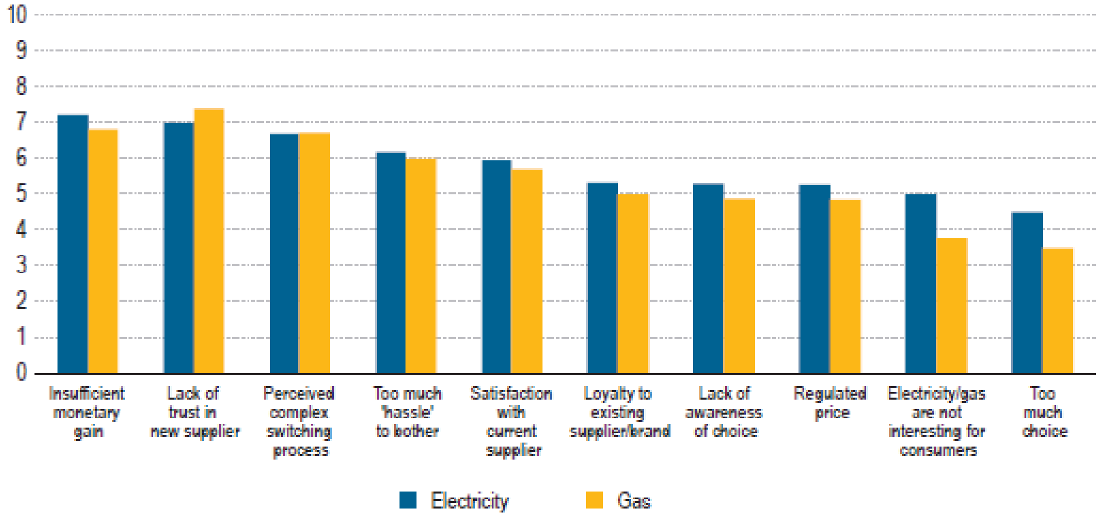
[177] The Czech Republic, France, Germany, Italy, Lithuania, Poland, Slovenia, Spain, Sweden and the UK.

[178] "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

[179] For example, there were over 400 electricity and gas supply offers in Berlin alone in 2014 (source: ACER Database), making a comprehensive examination of all supply offers in the EU28 impracticable.

[180] The percentage of consumers changing suppliers in any given year.

Figure 2: Factors preventing electricity and gas consumers from switching – 2014 (1 – not at all important)

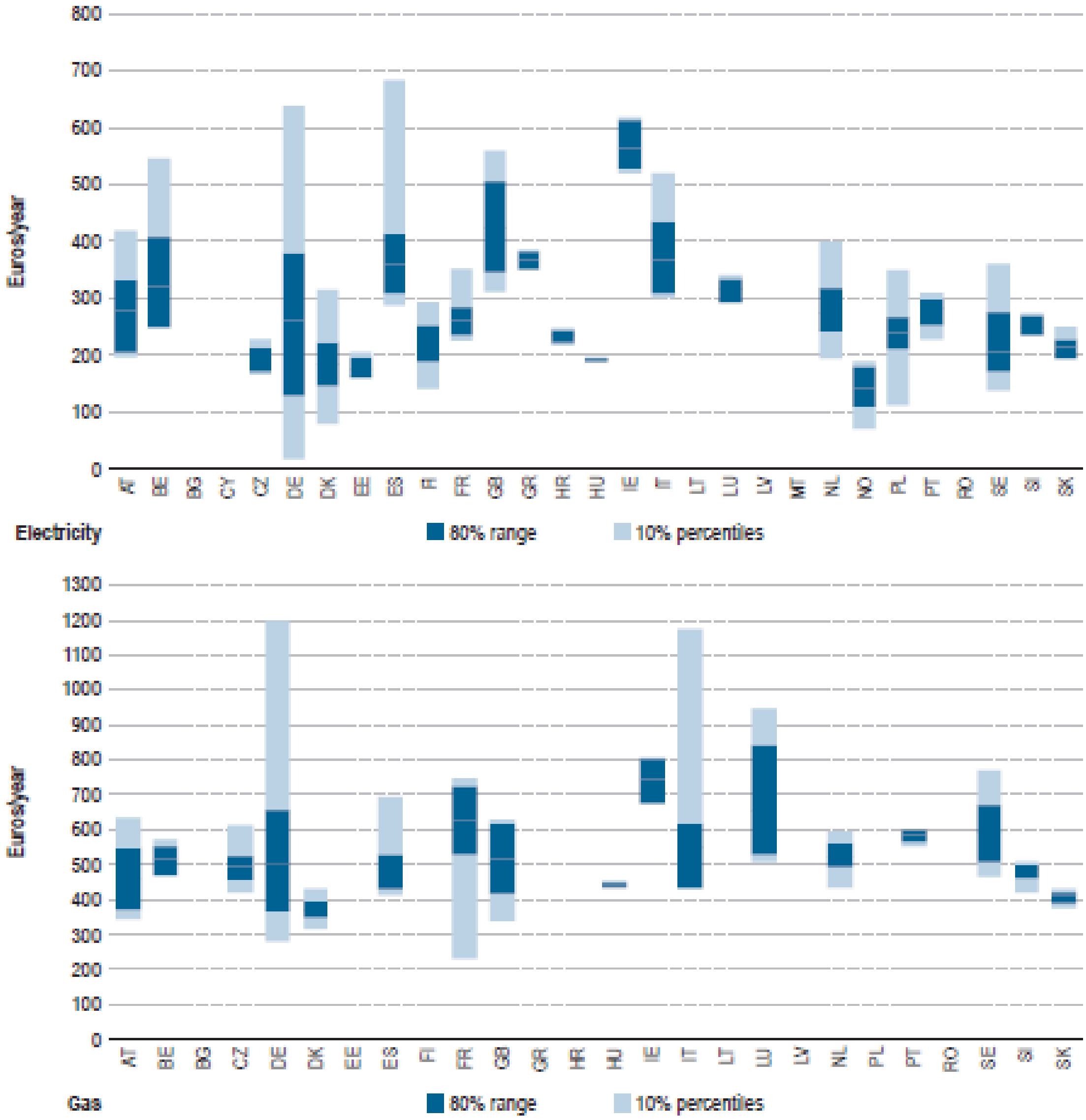


Source: ACER Questionnaire, February–April 2015

Consumer associations and NRAs report that insufficient monetary gain is the prime obstacle to switching (Figure 2 above). An ACER questionnaire suggests that the perceived minimum annual savings required by electricity consumers to switch in Belgium, Germany, Italy, Latvia, Poland and Slovenia lie in the range of 0–100 euros, whilst in the United Kingdom, the Netherlands, Portugal and Sweden, this was estimated be 100–200 euros. The switching trigger ranges were the same for gas consumers, with the exception of Italy, where switching trigger is estimated to be in the range of 100–200 euros.

Given that the difference in price between most offers in the market lie within comparable ranges to switching triggers (Figure 3 below), switching suppliers is a marginal decision for many household consumers. This highlights the importance of the broad variety of fees that consumers may be charged when they switch, as these diminish the (perceived) financial gains of moving to a cheaper tariff in what is already a marginal decision for many consumers.

Figure 3: Dispersion in the energy component of retail prices for households in capitals – December 2014



Source: ACER Retail Database (November–December 2014) and ACER calculations

Whilst the data indicates that switching is free for most EU consumers, a minority still face switching-related charges. First of all, exit (termination) fees may apply when leaving a fixed-term or fixed-price contract early[181]. The legitimacy of such fees are acknowledged in EU legislation (see Section 7.4.3 below), and they are often put in place to recoup the costs of equipment, discounts and/or other incentives provided at the beginning of the contract. A mystery shopping exercise in ten Member States revealed that whilst 77% of electricity suppliers stated that consumers would face no charges for switching, 17% were warned that they may be charged an exit fee (Table 1), a figure

[181] As sometimes occurs in Member States including NL and UK.

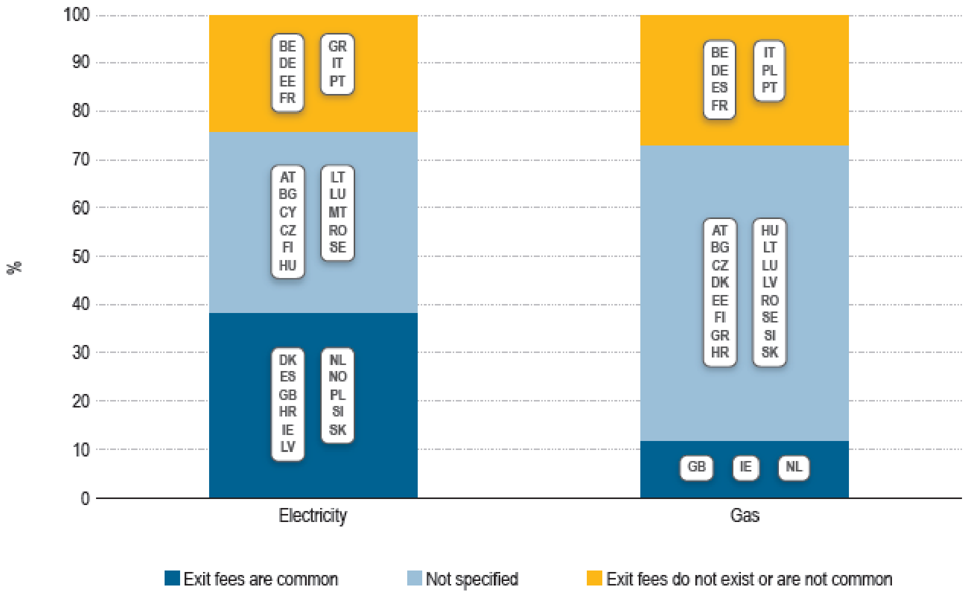
corroborated by ACER data suggesting that exit fees are still common in at least 11 Member States for electricity and 3 Member States for gas (Figure 4).

Table 1: Electricity providers' response when asked if there are any charges when switching electricity provider

	CZ	DE	ES	FR	UK	IT	LT	PL	SE	SI	Total
You will not be charged for the change	60%	94%	83%	89%	59%	86%	80%	67%	66%	80%	77%
A fee for cancelling your current energy deal (e.g. exit fee for fixed rates)	40%	5%	11%	5%	38%	1%	0%	28%	32%	14%	17%
Another extra charge	0%	0%	7%	4%	3%	11%	8%	4%	2%	2%	4%
No response	0%	1%	0%	1%	0%	1%	12%	1%	0%	4%	2%

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission

Figure 4: Existence of exit fees imposed by suppliers when switching offers - 2014



Source: ACER Questionnaire (February–April 2015) and ACER Database (November–December 2014).

Notes: Based on the offer data shown or as indicated by the respondents in the Questionnaire. Although MSs are listed in the Figure, the information drawn from the offer data may refer only to the capital city.

Aside from exit fees, however, the same mystery shopping exercise revealed that 4% of mystery shoppers were told they may be charged other fees related to switching, including administrative costs, start-up costs for a new or short-term service, or security deposits (Box 1 below). This finding is notable because EU legislation ensures that consumers "are not charged for changing supplier"[182]. As checks by the Commission

182 This reading was recently supported by the body representing the EU's national regulatory authorities – the Council of European Energy Regulators – who write: *"The 3rd Energy Package Directives*

indicate that this legislation has been correctly transposed into Member State law, the finding suggests either legal failures in the EU legislative text that prevent it from fulfilling its intention and/or non-enforcement by national authorities.

Box 1: Examples of “extra charges” when switching mentioned by electricity providers (when being contacted by phone)

- Administration cost (EUR 35) – France
- A service fee (EUR 27.90) – France
- A fee for starting up the service (EUR 27.16) – France
- An administration cost added on the first electricity bill (EUR 27.59) – Italy
- An activation fee – Italy, Poland
- An extra charge of EUR 20.54 on the first bill; no explanation was provided for this charge – Italy
- A security deposit (EUR 70) – Italy
- A deposit (EUR 77) – Italy
- A fee for contracts of less than one year – Spain
- A yearly charge of 300 SEK/year (or 25 SEK/month) for each new contract – Sweden

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission

In total, therefore, the results from these ten representative Member States suggest that around one fifth of electricity consumers in the EU would face some sort of fee associated with switching suppliers. As for the magnitude of switching-related charges, Figure 5 below indicates that average exit fees fall between 5 and 90 euros, depending on the capital city sampled. Electricity and gas consumers on fixed-price and fixed-term contracts in Amsterdam were the most affected by exit fees, and these could significantly reduce their saving potential from 16% (without exit fees) to 6% (with first-year exit fees included) with respect to the average incumbent standard offer for electricity consumers, and from 13% to 6% with respect to the average gas standard incumbent price. Exit fees could also considerably reduce potential savings for electricity consumers in Ljubljana, Dublin, Copenhagen, London and Warsaw.

clearly state that switching should be completely free for the customer." "*Position on early termination fees*" (2016) CEER, Ref: C16-CEM-90-06.

Figure 5: Potential effect of exit fees on annual savings to be made from switching away from the incumbent in Europe - 2014 (% and euros)[183]

Source: ACER.

While the possibility of charging exit fees may provide suppliers with more flexibility in the tariffs they are able to offer, they make comparisons more difficult for consumers and reduce the incentive for switching. Furthermore, behavioural economic theory suggests that all fees associated with switching can disproportionately discourage consumer action because of a decision making bias called 'loss aversion' – a tendency to strongly prefer avoiding losses (one-time switching fees) to acquiring gains (the long-term savings of moving to a cheaper tariff)[184]. This means the reduced incentives presented in Figure 5 will appear much more significant in the eyes of most household consumers – twice as large if findings from benchmark behavioural studies carry over into this real-world

183 Calculated on the basis of offer data for capital cities from the ACER Retail Database and the information from the consumer organisations. For those countries where standard offers are variable and where consumers typically incur exit fees while on fixed-term, fixed-price contracts, the above figure should be considered illustrative. 'Net' savings equal the difference between the incumbent price and the lowest offer, minus average exit fees typically imposed on fixed-term offers (i.e. savings for consumers after exit fees have been paid for). 'Gross' savings equal the difference between the incumbent price and the lowest offer. The data presented include information from the questionnaire (i.e. an assessment of the existence and the level of exit fees in Member States and the information collected on the basis of offer data in the ACER database to show the potential effect of exit fees in those MSs where these exist. The exit fees shown in the above figure are the averages of all exit fees incurred by consumers breaking away from contracts in the first year, and might be higher than those incurred when breaking away in the 2nd or 3rd year. In the case of electricity offers in Oslo and Warsaw, exit fees are estimated at 5% of the final standard offer.

184 "*Choices, Values and Frames*" (1984) Kahneman, D., and A. Tversky, American Psychologist, 39, 341-350.

context[185]. As a result, three Member States (Belgium, France and Italy) have outlawed altogether contract exit fees for household consumers in the energy sector.

Box 2: Switching energy suppliers in Belgium

As from 13 September 2012, the Belgian Electricity Act was amended (see Article 18, Section 2 and 3 of the Electricity Act) and suppliers were no longer permitted to charge households and SMEs (non-residential users with a maximum annual usage of 100,000 kWh in natural gas and 50,000 kWh in electricity) a fee for the early termination of a contract, provided that a one-month notice period is observed.

The abolition of early termination, or exit fees seems to have had a positive impact on the market with regard to the number of users switching to a different electricity and gas provider. Switching jumped markedly in all Belgian regions for bot electricity and gas around the time of the legislative change. This has led NEON – the Europe-wide network of energy ombudsmen and mediation services – to suggest that the ban on switching fees may have been to credit for this.

	2011	2012	2013	2014
Brussel - elektriciteit	4,1%	8,3%	14,3%	9,6%
Vlaanderen - elektriciteit	8,2%	16,5%	15,4%	11,9%
Wallonië - elektriciteit	8,6%	11,6%	13,6%	12,7%
Brussel - aardgas	4,7%	9,3%	18,3%	10,5%
Vlaanderen - aardgas	9,2%	18,9%	18,7%	13,9%
Wallonië - aardgas	11,0%	15,0%	21,2%	15,9%

The Belgian Ombudsman also found that the number of complaints with regard to switching providers has significantly fallen since the amendment of the act on 25 August 2012, from 14% (1,854 complaints) in 2014 to 8% in 2012 (1,250 complaints), 3% in 2013 (347 complaints) and 3.5% in 2014 (318 complaints).

Source: NEON, The National energy Ombudsman Network

One final factor to take into account is a high level of uncertainty amongst consumers over whether they *could* be charged for switching – a fact that may be discouraging many from looking into the possibility of switching because of the perceived complexity of it. Whereas the evidence suggests only around 20% of consumers in the EU would actually face some sort of fee associated with switching suppliers, 39% of consumers surveyed[186] did not know whether or not they would be charged. This does not include 17% that responded with certainty that they could be charged a fee for switching.

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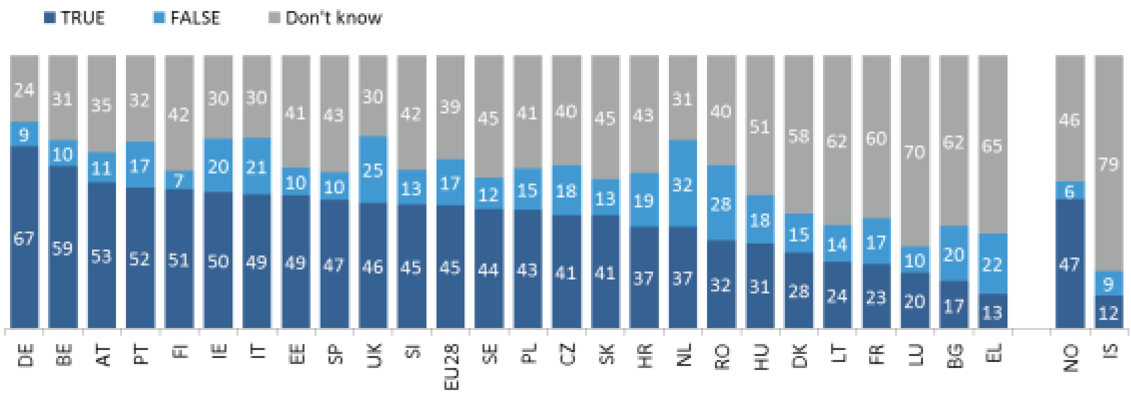
[185] "*Loss Aversion in Riskless Choice: A Reference-Dependent Model*" (1991) Tversky, A., and D. Kahneman, Quarterly Journal of Economics, 106 (4), 1039–1061.

[186] 29,119 interviews were conducted across 30 countries (EU28, Iceland and Norway). "*Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU*" (2016) European Commission.

Figure 6: Knowledge of switching rules – no charge when changing electricity company, by country[187]



Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission

A lack of information relevant to switching in bills is one explanation for this. Whereas customers in the majority of Member States are currently provided with information on the consumption period, actual and/or estimated consumption, and a breakdown of the price, there is a greater diversity of national practices with regards to other information, including switching information, and the duration of the contract[188].

Another explanation is incomplete information from suppliers themselves. Table 2 below shows that mystery shoppers in ten representative Member States were often unable to find any information on switching rules whatsoever on electricity companies' websites.

[187] Question: "The following are statements regarding consumer rights in the energy sector. Please indicate whether each statement is true or false: "If you decide to change your electricity company, you will not be charged for the change“".

[188] For more details, see the Thematic Evaluation on Metering and Billing.

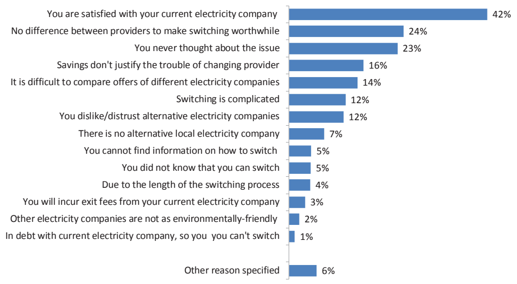
Table 2: Switching rules found on electricity companies' websites[189]

	SI	DE	UK	FR	PL	CZ	IT	LT	SE	ES	Total
	50	**100**	**75**	**75**	**100**	**50**	**75**	**50**	**50**	**75**	**700**
You will not be charged for the change	82%	57%	21%	52%	50%	36%	45%	30%	10%	24%	42%
The new provider must make the change within three weeks (or less), provided you respect the terms and conditions of the original contract	10%	13%	26%	13%	6%	8%	1%	10%	12%	3%	10%
Within six weeks (or less) after you switch, you should receive the final closure account from your previous provider	10%	11%	24%	4%	7%	2%	0%	2%	2%	4%	7%
It might be that you'll incur a fee for cancelling your current energy deal	10%	5%	17%	0%	6%	8%	1%	0%	16%	5%	7%
None of the above	14%	38%	42%	43%	47%	52%	54%	66%	66%	69%	49%

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission

High uncertainty levels indicate that the current prevalence of switching-related charges may be having a much broader impact on switching rates than would be expected if only consumers directly affected by such charges were considered. Whereas only 3% of survey respondents stated that one of the main reasons they had not tried to switch was that they would incur an exit fee from their electricity company, 16% stated that the savings would not justify the trouble linked to changing electricity companies, 14% that it is difficult to compare offers, and 12% that they perceive switching as being too complicated – each a response that could have been influenced by the uncertain prospect of switching-related charges.

Figure 7: Main reasons for not trying to switch electricity company[190]



Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission

Given the persistently low levels of switching and consumer engagement in the energy sector (Figure 1), there may therefore be scope to further restrict the use of fees charged to consumers for changing suppliers. This would remove a key monetary barrier to greater consumer engagement. It would make it easier for consumers to control their bills and harder for suppliers to lock consumers into disadvantageous contracts. Such action

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189 Question: "Which of the following statements about the switching process were found on the website? (multiple answers allowed)".

190 Question: "What are the main reasons for not trying to switch your electricity company? (up to three responses)".

would therefore be consistent with other provisions in the Electricity and Gas Directives which state: “Member States shall ensure that the eligible customer is in fact easily able to switch to a new supplier”.

Without intervention, switching-related fees in the range of 5 to 90 euros would likely continue to affect an estimated 20% of electricity consumers in the EU, with uncertainty over their applicability influencing the decision-making of well over half of all EU electricity consumers. A lack of action to limit these fees would amount to ignoring a key barrier to consumer engagement.

Although there is less evidence on switching-related fees in the gas sector, Figures 4 and 5 suggest they are prevalent in fewer Member States, and that their magnitude is similar.

7.4.3. *Deficiencies of the current legislation*

The consumer protection provisions in the Electricity and Gas Directives regulate switching fees. Largely unchanged since their 2001/2003 introduction, these provisions state that “customers are not to be charged for changing supplier”.

The following text regarding contract exit fees was added in 2007: contracts must specify “whether withdrawal from the contract without charge is permitted”. It weakened the initial provision by affirming the permissibility of certain switching-related charges without explicitly addressing whether the legislation addressed all switching-related charges in categorically exhaustive manner.

As addressed in Section 7.1.1 and Annex IV of the Evaluation, the current framework therefore remains both complex and open to interpretation with regard to the nature and scope of certain key obligations.

7.4.4. *Presentation of the options*

Option 0: Stronger enforcement

Stronger enforcement to tackle the switching fees currently imposed contrary to EU legal requirements.

Option 0+: Clarifying certain concrete requirements in the current legislation through an interpretative note, coupled with stronger enforcement

This option involves making it explicit that the existing Third Package provision stating that consumers "are not charged for changing supplier" applies to contract switching fees. This would seek to remove any legal uncertainty and improve Member State compliance.

Option 1: Legislation to outlaw the use of switching fees and to limit the use of exit fees in electricity and gas supply contracts in the EU

In concrete terms, the preferred measures will include the following:

i. Define switching fees and contract exit fees in the legislation.

ii. Ban all switching fees, and ban exit fees in open-ended supply contracts and fixed term contracts that have come to the end of the agreed term.

iii. For fixed-term contracts, permit exit fees if the contract has not ended, but ensure the cost-reflectiveness and proportionality of these fees to avoid undue consumer detriment. Clarify that consumers should always have the possibility to exit the contract, if they are prepared to pay the exit fee.

iv. Define exceptions to accommodate certain on-bill repayment of upfront investments in, *inter alia*, energy efficiency financed by suppliers or energy service providers.
v. Introduce transparency provisions so that fees are presented in an easily understandable manner (e.g. amortisation schedule) in contracts and pre-contractual information.
vi. Clarify that commercial and industrial supply contracts would not be affected.

Option 2: Legislation to categorically outlaw the use of all switching and exit fees in electricity and gas supply contracts to EU household consumers

In concrete terms, the preferred measures will include the following:
i. Define switching fees and contract exit fees in the legislation.
ii. Ban all fees defined in i).

7.4.5. *Comparison of the options*

This section compares the costs and benefits of each of the Options presented above in a semi-quantitative manner.

In general, the costs of implementing each of the above measures can be estimated to a reasonably certain degree using tools such as the standard cost model for estimating administrative costs. However, no data or methodology exists to accurately quantify all the benefits of the measures in terms of direct benefits to consumer (consumer surplus) or general competition. As such, this Section aims to illustrate the possible direct benefit to consumers assuming certain conditions. It also highlights important qualitative evidence from stakeholders that policymakers should also incorporate into their analysis of costs and benefits.

Option 0: Stronger enforcement

An estimated 4% of EU consumers face switching-related charges that may be illegal under EU law. Stronger enforcement would see these increasingly phased out. Whilst we cannot measure the economic benefits of this option, we can estimate its benefit to consumers given some simple assumptions.

If we assume that:
- One in fifty of the households currently affected by illegal electricity switching fees make a switch as a direct result of an enforcement drive[191];
- Gas household consumers see no benefits[192];

[191] This is a highly uncertain figure, affected by several variables that have not been studied in depth, including the speed and effectiveness of EU enforcement action, and public awareness of consumer rights.
[192] This is a conservative estimate. Whilst the evidence suggests they may be less prevalent, and Figure Figures X and Y indicate they are certainly present.

- The annual financial benefit of switching for these households amounts to 82 euros, which is the average difference in price between the incumbent's standard offer and the cheapest offer in the capital city in the EU[193];
- The financial advantage of switching as a result of these measures persists for four years[194];
- All EU households within each Member State are able to benefit from these changes equally in relative terms[195];
- A discount rate of 4% for the consumer benefits year on year;

then Option 0 would result in an increase in consumer surplus **of between 13.7 million euros and 48.4 million euros annually** (depending on the year of implementation), and **415 million euros in total for the period 2020-2030**.

In spite of these considerations, it is unlikely that Option 0 would most effectively address the problem of poor consumer engagement. First, a great degree of uncertainty surrounds the estimation above associated with the speed and effectiveness of EU enforcement action.

In addition, the effectiveness of Option 0 is significantly limited by the fact that the provisions of the Electricity and Gas Directives state that consumer supply contracts must specify "whether withdrawal from the contract without charge is permitted". A further 17% of consumers will therefore continue to be directly affected by contract exit fees that are legal under current legislation.

There are **no implementation costs** associated with Option 0.

Option 0+: Clarifying certain concrete requirements in the current legislation through an interpretative note, coupled with stronger enforcement

This option would make it easier for suppliers and national authorities to interpret current switching rules and to determine whether certain fees are compatible or incompatible with the Third Package. Consumers would also have access to more and clearer information regarding the legal situation surrounding such fees and could become better aware of the types of fees used in their contracts. This option would make it easier for suppliers and national authorities to interpret current switching rules and to determine whether certain fees are compatible or incompatible with the Third Package. Consumers would also have access to more and clearer information regarding the legal situation surrounding such fees and could become more aware of the types of fees used in their contracts.

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193 The weighted average was not used because the large potential savings available to DE consumers skewed this figure to over EUR 150. "*Market Monitoring report 2014*" (2015) ACER, http://www.acer.europa.eu/Official_documentsreality, /Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015, p.59.

194 A conservative assumption given the implied average time between switches is upwards of 15.5 years for electricity consumers and 18 years for gas consumers.

195 In reality, households will react differently depending on consumers' needs, skills, motivations, interests, lifestyle, and access to resources such as accurate online comparison tools. However, we have no reliable data to quantify these differences in this specific context.

Whilst the economic benefits of this measure cannot be estimated, we can expect its benefits to consumers to be similar to Option 0 (**415 million euros in total for the period 2020-2030**) or higher, reflecting the greater legal certainty engendered by the EU guidance issued compared with Option 0.

However, as with Option 0, a further 17% of consumers are directly affected by contract exit fees that are legal under current legislation.

It is unlikely that voluntary cooperation between Member States would address this problem, as it is domestic in nature with no common gains to be had through supra-national coordination.

There are **no implementation costs** associated with Option 0+.

Several **stakeholders** support the principle of better implementation of the existing switching fee provisions in the Electricity and Gas Directives, including the European Parliament's ITRE Committee and NRAs. Others, such as consumer groups and ombudsmen, argue that there should be no fees associated with switching.

Option 1: Legislation to outlaw the use of switching fees and to limit the use of exit fees in electricity and gas supply contracts in the EU

This option may considerably reduce the prevalence of both switching and exit fees for the category of consumers most likely to be confused by such fees – household consumers.

If we assume that:

- One in one-hundred of the 17% of households currently affected by exit fees in their electricity supply contracts make a switch as a direct result of this intervention[196];
- The annual financial benefit of switching for these households amounts to 82 euros, which is the average difference in price between the incumbent's standard offer and the cheapest offer in the capital city in the EU[197];
- Gas household consumers see no benefits[198];
- The financial advantage of switching as a result of these measures persists for four years[199];

[196] This is a highly uncertain figure as we have no clear and comprehensive picture as to: i) the proportion of consumers who may be charged exit fees even though they are on indefinite contracts; ii) the proportion of consumers whose exit fees would be considered disproportionate, and therefore not permitted under this option; iii) the extent to which consumers benefitting from this measure would be aware of it; iv) how those aware of the legislative change would respond to the increased financial incentive to switch.

[197] The weighted average was not used because the large potential savings available to DE consumers skewed this figure to over EUR 150. "*Market Monitoring report 2014*" (2015) ACER, http://www.acer.europa.eu/Official_documentsreality, /Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015, p.59.

[198] This is a conservative estimate. Whilst the evidence suggests they may be less prevalent, Figures 4 and 5 indicate they are certainly present.

- All EU households within each Member State are able to benefit from these changes equally in relative terms[200];
- A discount rate of 4% for the consumer benefits year on year;

then Option 1 would result in an increase in consumer surplus **of between 29 million euros and 102.8 million euros annually** (depending on the year of implementation), and **881 million euros in total for the period 2020-2030** on top of any gains brought by improved enforcement (estimated at 415 million euros for options 1 and 2).

Whilst these consumer benefits are subject to great uncertainty due to the unknown extent to which they would increase consumer switching, Belgium's experience (See Box) would seem to indicate that restricting contract exit fees has a significant potential to increase consumer engagement – in the short-term at least.

In terms of **implementation costs**, Option 1 would most notably limit innovation and consumer choice around certain elements of consumer supply contracts, most notably by preventing exit fees from being charged in indefinite contracts. Whilst unquantifiable, these implementation costs would likely be limited. Consumers wishing to benefit from lower prices in exchange for greater consumer loyalty could still opt for fixed-term contracts.

In addition, Option 1 would permit the on-bill repayment of upfront investments in energy efficiency. Such financing through, for instance, energy performance contracting[201] will play an important part in meeting the EU's ambitious energy efficiency targets, and is a priority under Commission plans.

Apart from consumer groups and ombudsmen, **most stakeholders would seem to support this option**, including suppliers and NRAs. This is because it incrementally builds upon the existing provisions of the Electricity and Gas Directives, helping to achieve the legislators' intention more effectively.

This option would best clarify the legal situation and be the most enforceable measure. Given the very significant effect on switching rates similar measures have had in Belgium (See Box 2), this measure would also lead to a sizeable increase in consumer engagement in many Member States in which contract exit fees are common.

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199 A conservative assumption given the implied average time between switches is upwards of 15.5 years for electricity consumers and 18 years for gas consumers.

200 In reality, households will react differently depending on consumers’ needs, skills, motivations, interests, lifestyle, and access to resources such as accurate online comparison tools. However, we have no reliable data to quantify these differences in this specific context.

201 "Energy performance contracting" means a contractual arrangement between the beneficiary and the provider of an energy efficiency improvement measure, verified and monitored during the whole term of the contract, where investments (work, supply or service) in that measure are paid for in relation to a contractually agreed level of energy efficiency improvement or other agreed energy performance criterion, such as financial savings.

If we assume that:

- One in four of the estimated 3% of household consumers who report that they have not tried to switch because they would be charged a fee actually make a switch as a result of a complete ban on such fees[202];
- The annual financial benefit of switching for these households amounts to 41 euros, which is half of the average difference in price between the incumbent's standard offer and the cheapest offer in the capital city in the EU[203];
- Gas household consumers see no benefits[204];
- The financial advantage of switching as a result of these measures persists for four years[205];
- All EU households within each Member State are able to benefit from these changes equally in relative terms[206];
- A discount rate of 4% for the consumer benefits year on year;

then Option 2 would result in an increase in consumer surplus **of between 64 million euros and 227 million euros annually** (depending on the year of implementation), and **1.9 billion euros in total for the period 2020-2030** on top of any gains brought by improved enforcement (estimated at 415 million euros for options 1 and 2).

Whereas **the implementation costs of Option 2 are unquantifiable, they may be significant**. This is because Option 2 would strongly restrict the range of contracts available to consumers, which may impede competition, as well as the provision of a legitimate class of products.

If implemented poorly, Option 2 could also impede the development of innovative financing options for beneficial investments in energy assets for households. Such products may require certain forms of termination fees in order to allow companies to recoup upfront investment costs provided as part of an integrated energy service product e.g. solar panels or energy efficiency upgrades. This option could therefore be in significant tension with other EU policy priorities, including its energy efficiency, renewable deployment, and self-consumption policies. For example, one of the objectives of the EED was to identify and remove regulatory and non-regulatory barriers to the use of energy performance contracting and other third-party financing arrangements for energy savings.

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[202] See Figure 7. This estimate is based on survey responses, and has been discounted to conservatively reflect possible unreliability in what consumers report.

[203] We conservatively assume that the savings to consumers available in this option are significantly reduced because the cheapest option available in the market – the benchmark price used in the other options – is usually a fixed term contract, which may require the consumer to accept a contract exit or termination fee in return for consumer loyalty. As this option entails banning all exit fees, it is unlikely that suppliers would be able to offer consumers the same level of financial savings in such contracts.

[204] This is a conservative estimate. Whilst the evidence suggests they may be less prevalent,
Figure 4 and Figure indicate they are certainly present.

[205] A conservative assumption given the implied average time between switches is upwards of 15.5 years for electricity consumers and 18 years for gas consumers.

[206] In reality, households will react differently depending on consumers' needs, skills, motivations, interests, lifestyle, and access to resources such as accurate online comparison tools. However, we have no reliable data to quantify these differences in this specific context.

Whereas several **stakeholders** support an outright ban on switching fees – notably consumer groups and energy ombudsmen – NRAs believe the decision on whether or not to completely ban them should be taken at the national level. ACER and electricity suppliers support the legitimacy of termination fees for fixed term contracts.

Conclusion

The analysis indicated that each of the Options above is likely to result in a net benefit. However, Option 1 is the preferred option, as it represents the most favourable balance between probable benefits and costs. Whereas the potential benefits of Option 2 are greater, so are the potential implementation costs in terms of both reduced competition and tension with the EU's sustainable energy policies.

7.4.6. *Subsidiarity*

Consumers are not taking full advantage of competition on energy markets due, in part, to obstacles to switching. Well designed and implemented consumer policies with a European dimension can enable consumers to make informed choices that reward competition, and support the goal of sustainable and resource-efficient growth, whilst taking account of the needs of all consumers. Increasing confidence and ensuring that unfair trading practices do not bring a competitive advantage will also have a positive impact in terms of stimulating growth.

As a result of current EU provisions, national legal regimes remain fragmented as regards switching-related fees. Further restricting such fees would diminish an important barrier to customer mobility. The possibility of easy and free-of-charge switching would exert more competitive pressure on energy suppliers to improve quality and reduce prices.

The options here envisage clarifying the legislation and further limiting the use of exit fees across different kinds of consumer contracts (fixed-term, indefinite, supply contracts bundled with energy services) and to different degrees.

The legal basis for the legislative options proposed (Options 1 and 2) is therefore likely to be Article 114 TFEU. This allows for the adoption of "measures for the approximation of the provisions laid down by law, regulation or administrative action in Member States which have as their object the establishment and functioning of the internal market". In doing this, in accordance with Article 169 TFEU, the Commission will aim at ensuring a high level of consumer protection.

Without EU action, the identified problems related to the lack of an EU-wide market will continue to lead to consumer detriment.

Option 0+
The guidance option does not significantly change the legal *status quo*. Member State authorities would continue, to have a significant degree of discretion in deciding if a termination/switching fee is allowed or not.

From a subsidiarity perspective, this option allows member States to decide on the extent to which they wish creating an environment where customers are encouraged to switch more freely, as this – in theory, at least – may not always result in lower overall prices depending on the national situation.

From the perspective of proportionality, however, this option would not achieve the objective of the Article of the Treaty taken as their legal basis – the establishment and functioning of the internal market.

Option 1
The principles of subsidiarity and proportionality are best met through this Option, as it is not overly prescriptive and will concretely reduce levels of consumer detriment that are, at present, not addressed at a national level by Member State authorities.

This option aims primarily at clarifying and not strengthening existing legislation. As switching and exit fees are already addressed in EU provisions, the subsidiarity and proportionality principles have clearly been assessed previously and deemed as met.

Box 1: Impacts on different groups of consumers

The benefits of the measures contained in the preferred option (Option 1), described in detail in the preceding pages, accrue predominantly to consumers who are engaged in the market – those who compare offers and are likely to change suppliers if they find a better deal. Whilst facilitating switch will also increase consumer engagement levels, and whilst the increased competition engendered by easier switching will lead to more competitive offers on the market, disengaged consumers, including consumers who may be vulnerable, will not reap as many direct benefits from this policy intervention

Option 2
Banning exit fees in EU legislation would help to create a level playing field for consumers within Member States and between Member States. At this point, however, it would be disproportionate to impose a complete ban on exit fees as it would have a limiting effect on innovation and choice. It would limit the range and number of offers available to consumers, for example, fixed-term, fixed-price contracts that offer a lower cost per kWh.

7.4.7. *Stakeholders' opinions*

Public Consultation
222 out of 237 respondents to the Commission's Consultation on the Retail Energy Market[207] believed that transparent contracts and bills were either important or very important for helping residential consumers and SMEs to better control their energy consumption and costs.

When asked to identify key factors influencing switching rates, 89 respondents out of 237 stated that consumers were not aware of their switching rights, 110 stated that prices and tariffs were too difficult to compare due to a lack of tools and/or due to contractual conditions, and 128 cited insufficient benefits from switching.

Only 32 out of 237 respondents agreed with the statement: "There is no need to encourage switching". 98 disagreed and 90 were neutral.

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[207] Held from 22 to 17 April 2014. https://ec.europa.eu/energy/en/consultations/consultation-retail-energy-market

National Regulatory Authorities
ACER identifies exit fees as a potential barrier to switching, since they tend to increase the threshold for consumers to switch due to the perceived diminished potential savings available. However, ACER highlights that exit fees in fully competitive retail markets are applied to cover the costs incurred by suppliers due to early contract termination. ACER argues that offers which include exit fees should be made fully transparent (including on price comparison tools) and that exit fees need to be objectively justified.

The body representing the EU's national regulatory authorities in Brussels, **CEER**[208], supports the distinction between exit fees, which it deems to be a contractual matter, and all other switching-related fees. CEER has stated that it should not be possible for energy suppliers to charge an exit fee to customers who respect the end date of their fixed term energy contract. It also deems that other switching-related fees are not permissible under EU law. However, it argues that any decision on whether to abolish exit fees needs to be taken at the national level, as creating an environment where customers are encouraged to switch more freely may not always result in lower overall prices.

Ombudsmen
According to **NEON**, the National Energy Ombudsmen Network, EU regulations and directives already provide that supplier switching should be easy and quick, without extra charges. However, mistrust in the market, indecision and the perceived lack of benefits remain the main obstacles to more switching. As it is the case in France and Belgium, NEON believes that consumers should be allowed the right to change supplier whenever they want, without paying termination or exit fees.

Consumer Groups
BEUC has argued for greater transparency on exit fees, stating that a summary of the key contractual conditions, including conditions for switching, should be provided to consumers in concise and simple language alongside with the contract[209]. BEUC has also stated that it is: "concerned about the application of termination fees representing a lock in situation of the consumer and an anti-competitive measure as these fees often prevent consumers from changing the supplier. Switching should not be subject to any termination fee or penalty"[210].

BEUC, **EURELECTRIC** and **Eurogas** recently released joint statement on improved comparability of energy offers[211]. In it, they call for the following key information is provided to customers by suppliers in one place in a short, easily understandable, prominent and accessible manner:

- Product name and main features including, where relevant, information on environmental impact, clear description of promotions (e.g. temporary discounts) and additional services (e.g. maintenance, insurance, etc.)

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[208] The Council of European Energy Regulators.

[209] http://www.beuc.eu/publications/beuc-x-2015-102_mst_beuc_response_to_public_consultation_on_a_new_energy_market_design.pdf

[210] http://www.beuc.eu/publications/beuc-x-2015-068_mst_building_a_consumer-centric_energy_union.pdf

[211] http://www.eurelectric.org/media/263669/joint_statement_-_improved_comparability_of_energy_offers_-2016-030-0116-01-e.pdf

- Total Price (fixed/variable) - which includes all cost components - and conditions for price changes
- Contract duration, notice period (renewal/withdrawal - where relevant) and conditions for termination, including, where relevant, fees and penalties
- Payment frequency and method options (e.g. cash/ cheque/ direct debit/ standing order/ prepayment)
- Supplier's contact details (e.g. customer service's address, telephone number and/or email, including, where relevant, identification of any intermediary)

Suppliers
In their contribution to the discussions within the Citizens' Energy Forum in 2016, **EURELECTRIC** and its members welcomed the intention of the Commission and NRAs to work towards removing barriers to switching supplier. EURELECTRIC believes that all barriers should be considered, including non-commercial barriers, i.e. technical and regulatory. In terms of commercial barriers, a distinction should be drawn between fixed term contracts and variable contracts. Many customers are on variable tariffs with no end date and these do not have exit fees. In contrast, according to EURELECTRIC, exit fees need to be allowed to for fixed term deals – provided they're proportionate to the costs incurred by the supplier – as they help cover the costs suppliers face when customers leave early, much like for broadband or mobile phone contracts. Such contracts can be cheaper because suppliers have more certainty about how many customers they have and how much energy to buy in advance. If exit fees were banned for such contracts, the prices of fixed term deals would be likely to go up to the detriment of customers. EURELECTRIC believes that in any case where exit fees do apply to fixed term contracts, they must be clearly communicated to customers up-front.

BEUC, **EURELECTRIC** and **Eurogas** also recently released joint statement on improved comparability of energy offers, which can be read above. It notably includes the recommendation that termination fees be provided along with other key information on the offer "in one place in a short, easily understandable, prominent and accessible manner".

The European Parliament
In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the Parliament's **Committee on Industry, Research and Energy (ITRE)**: "Insists that the provisions on switching, as set out in the Third Package, should be fully implemented by Member States, and that national legislation must guarantee consumers the right to change suppliers in a quick, easy and free-of-charge way, and that their ability to switch should not be hindered by termination fees or penalties". Furthermore, ITRE calls for better information to consumers about their rights, and for further measures to make switching between providers easier.

In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the Parliament's **Committee on the Internal Market and Consumer Protection (IMCO)** called for: "the full implementation of the third energy package, including the right to change suppliers free of charge and better information to consumers about their rights, and for further measures to make switching between providers easier and faster, including a shortened switching period and effective and secure data portability in order to prevent the lock-in of consumers".

The Committee of the Regions
In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the **Committee of the Regions** suggests that information

campaigns for switching suppliers should be launched by energy regulators, local authorities and consumer organisations. The Committee also encourages the EU to adopt an ambitious regulation on reducing the transfer time for customers switching from one provider to another, and making the transfer procedure automatic.

7.5. Comparison tools

7.5.1. *Summary table*

Objective: Facilitating supplier switching by improving consumer access to reliable comparison tools.		
Option 0+	**Option 1**	**Option 2**
Cross-sectorial Commission guidance addressing the applicability of the Unfair Commercial Practices Directive to comparison tools	Legislation to ensure every Member State has at least one 'certified' comparison tool that complies with pre-specified criteria on reliability and impartiality	Legislation to ensure every Member State appoints an independent body to provide a comparison tool that serves the consumer interest
Pros: - Facilitates coherent enforcement of existing legislation. - Light intervention and administrative impact. - Cross-sectorial consumer legislation already requires comparison tools to be transparent towards consumers in their functioning so as not to mislead consumers (e.g. ensure that advertising and sponsored results are properly identifiable etc.). - Cross-sectorial approach addresses shortcomings in commercial comparison tools of all varieties. - Cross-sectorial approach minimizes proliferation of sector-specific legislation.	Pros: - Fills gaps in existing legislation vis-à-vis energy comparison tools. - Limited intervention in the market, in most cases. - Allows certifying all existing energy comparison tools regardless of ownership. - Proactively increases levels of consumer trust. - Ensures EU wide access. - The certified comparison websites can become market benchmarks, foster best practices among competitors	Pros: - NRAs able to censure suppliers by removing their offers from the comparison tool. - No obligation on private sector. - Reduces risks of favouritism in certification process. - Proactively increases levels of consumer trust.
Cons: - Does not apply to non-profit comparison tools. - Does not proactively increase levels of consumer trust. - The existing legislation does not oblige comparison tools to be fully impartial, comprehensive, effective or useful to the consumer.	Cons: - Existing legislation already requires commercial comparison tools to abide by certain of the criteria addressed by certification. - Requires resources for verification and/or certification. - Significant public intervention necessary if no comparison tools in a given Member State meet standards.	Cons: - To be effective, Member States must provide sufficient resources for the development of such tools to match the quality of offerings from the private sector. - Well-performing for-profit tools could be side-lined by less effective ones run by national authorities.
Most suitable option(s): Option 1 is the preferred option because it strikes the best balance between consumer welfare and administrative impact. It also gives Member States control over whether they feel a certification scheme or a publicly-run comparison tool best ensures consumer engagement in their markets.		

7.5.2. *Description of the baseline*

Online comparison tools – websites that compare different energy offers – play an important role in helping consumers to make an informed decision about switching suppliers. Comparison tools (CTs) have become increasingly widespread, and can now be found in almost every MEMBER STATE (Table 1).

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Comparison tools

Table 1: Estimated number of energy comparison tools in Member States[212]

Member State	*Number of energy CTs*	*Of which Govt. Operated*	*Comment*
** denotes estimate based on weighted average of figures from NRAs who reported data, or desktop research*			
AT	2*	1	
BE	11	3	Accreditation under review.
BG	0	0	
CZ	2*	0*	
DE	10	0	German consumer organisations under the umbrella of a market watchdog have conducted a survey about CT's in February 2016 and provided a test report and ranking, which can be found here.
DK	2	2	
EE	0	0	
EL	3*	0*	
ES	7	1	The NRA is legally entitled to run a CT. All suppliers are obliged to send the commercial offers to the CT. The NRA CT would meet accreditation standards. The consumer organization also has a CT, but only for its affiliates. The NRA has no powers to monitor the functioning of private CTs. It can be estimated than very few of them would meet accreditation standards, perhaps between 0 and 3, depending on the requirements for the accreditation.
FI	4	1	No specific accreditation standards are applied. The CT (www.sahkonhinta.fi) operated by the NRA, however, is free of charge, neutral, easy to access and comprehensive (all suppliers are obliged to report their public offers there). One of the commercial CTs uses the price data that is published by the NRA.
FR	8	2	
HU	3	0	There are several running service provider businesses concentrating exclusively on businesses. In addition Hungary is considering implementing a comparison tool - taking into account the level of price competition - would primarily focus on businesses and would be run by the Hungarian NRA.
HR	1*	0*	
IE	2*	0	Accreditation scheme in place
IT	9	2	
LV	0	0	
LT	0	0	ACER reports no price comparison tools in this Member State.
LU	1	1	

212 Excluding CY and MT. Source: CEER, "*Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools*", (2014) European Commission, http://ec.europa.eu/consumers/consumer_evidence/market_studies/comparison_tools/index_en.htm.

Member State	*Number of energy CTs*	*Of which Govt. Operated*	*Comment*
** denotes estimate based on weighted average of figures from NRAs who reported data, or desktop research*			
NL	14	0	No accreditation scheme. ACM developed a 'guidance' document for all companies offering electricity and/or gas contracts, including price comparison websites. The guideline is based on general consumer law and sector specific energy legislation. The goal of the guideline is to ensure that consumers are offered energy products that are tailored made to their situation, contains information they can easily understand, and compare with other offers. ACM can intervene whenever a price comparison website does not comply with the aforementioned legislation.
PL	1	1	Offers available on CT, are updated by NRA on the basis of information from suppliers. Suppliers are obliged to send NRA new offers immediately after deciding on the introducing their offer into the market (but not later than 2 days before the offer starts). However data concerning distribution is entered by particular DSO on the basis of distribution tariffs and their changes.
PT	2	1	
RO	0	0	
SE	4	1	The regulated CT is under supervision and checked regularly. The other CTs are not regulated, supervised nor does the regulator control the prices or how the prices are published. There is no specific legislation for these CTs.
SI	1*	1	
SK	1*	0*	
UK	34	1	33 comparison tools make up over 90% of the market in GB, with the remaining proportion of the market made up of 100's of smaller switching services.
Total	122*	18*	

Source: CEER and DG ENER research

A recent study found that 64% of consumers who had compared the tariffs of different electricity companies said they had used a comparison tool to do so, compared to 38% who had visited company websites, and 8% who had contacted companies by phone[213]. It also showed that comparison tools significantly increased the number of cheaper offers consumers were able to identify compared with contacting individual providers directly[214]. Overall, 23% of consumers surveyed in the EU have used a comparison tool to compare energy offers in the last 12 months[215].

[213] Non-exclusive figures i.e. respondents could choose more than one means of comparison.

[214] From twice to twenty times, depending on the Member State. "*Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU*" (2016) European Commission.

[215] However, this figure varies widely across the EU with up to 45% of UK consumers using comparison tools to compare energy offers compared to only 2% of consumers from Luxembourg. "*Study on the*

Comparison tools are likely to become even more important as the retail market for energy matures. Between 2012 and 2014, 'choice' for consumers in European capitals widened, with a greater variety of offers being available. However, the ability of consumers to compare prices can be hampered by the complexity of pricing and the range of energy products, as well as by an increasing number of offers and their bundling with additional charge free or payable services[216].

In a retail market characterized by persistently low levels of consumer engagement, comparison tools are an effective means of reducing search costs for consumers, and presenting them with accurate market information in a manner that is clear and comprehensive.

However, the majority of comparison tools are operated for profit, leading to situations where their impartiality and the consumer interest may not be ensured. Most comparison tools do not charge consumers for access to their sites and therefore the bulk of their products are obtained via commercial relationships with the vendors they list. They get paid via subscription fees, click-through fees, or commission fees. Some comparison sites list sellers at no cost and get their revenue from sponsored links or sponsored ads. A lesser used model is where some Comparison Tools charge consumers to obtain access to its information, while firms do not pay any fees (Figure 1).

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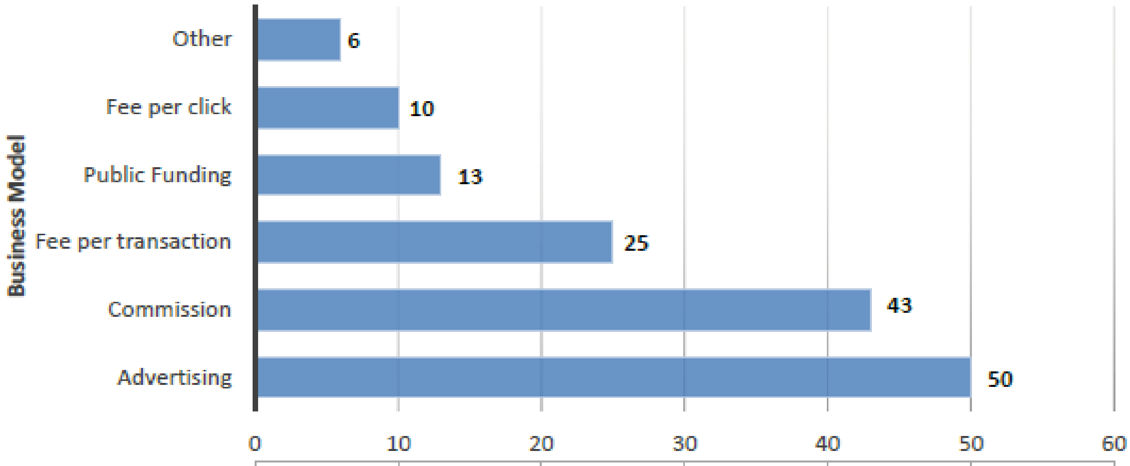
coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools" (2013) European Commission,, http://ec.europa.eu/consumers/consumer_evidence/market_studies/comparison_tools/index_en.htm

216 "*Market Monitoring report 2014*" (2015) ACER, http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015 p.40, 100.

Figure 1: Business models of EU comparison tools (including non-energy)



	Advertising	Commission	Fee per transaction	Public Funding	Fee per click	Other
Responses	50	43	25	13	10	6

Source: "Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools" (2013) European Commission, pp. 99, 102

Recent reports of unscrupulous practices have damaged consumer trust in both comparison tools and the switching process more generally (Box 1). Indeed, a third of respondents to a recent EU survey somewhat or strongly agreed that they did not trust price comparison websites because they were not independent and impartial and thus questioned the independence of such tools. Perhaps for this reason, the same study found: "Comparison tools did not appear keen to divulge details on how they generated income"[217].

Identified issues include:

i) the default presentation of deals by some websites;
ii) the misleading language used to provide consumers with a choice of which presentation to pick;
iii) the lack of transparency about commission arrangements; and
iv) inadequate arrangements for regulatory oversight.

[217] Less than half of Comparison Tools were willing to disclose details on their supplier relationship, description of business model or the sourcing of their price and product data. "*Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools*" (2013) European Commission, pp. xix, 191.

Box 1: UK House of Commons report into energy comparison tools[218]

> The UK has the largest number of energy comparison websites of any Member State, with 34 such tools controlling a 90% share of the market. In 2015, the House of Commons Energy and Climate Change Committee published a report criticising energy comparison tools for "hiding the best deals from consumers by concealing tariffs from suppliers that do not pay the website a commission." The report concluded that "all deals should be made available by default to the consumer" and strongly objected to "any attempt to lure consumers into choosing particular deals by the use of misleading language." In addition it highlighted "the lack of transparency about commission arrangements between the websites and suppliers" as a shortcoming in the UK energy comparison tool market.

Source: UK House of Commons, Energy and Climate Change Committee

The existing consumer *acquis* could be made to work better (see Section below), and is an *ex-post* safety net that is enforced on a case-by-case basis by relevant national courts and authorities. There may therefore be benefit in putting in place a specific *ex-ante* quality assurance mechanism to guarantee a high level of quality information and transparency to consumers, to spread the uptake of best practices, and to boost consumer confidence in these tools. In addition, while comparison tools are indeed widespread, there is the need to ensure a more universal coverage of reliable comparison tools throughout the internal market.

7.5.3. *Deficiencies of the current legislation*

Section 7.3.5 and Annex V of the Evaluation show that the relevance of the existing legislation is challenged by the fact that it is not adapted to reflect new ways of consumer-market interaction, such as through comparison tools.

The 2005 Unfair Commercial Practices Directive[219] (UCPD) addresses comparison tools in so far as it requires them to provide enough information to ensure that consumers are not misled. As such, comparison tools qualifying as traders under the UCPD must ensure that they carry out comparisons in a transparent way. They must not provide false or deceiving statements, nor must they omit information about products if this causes the average consumer to take a decision they might not have taken otherwise. The UCPD particularly requires all traders to clearly distinguish a natural search result from advertising.

Indeed, the full implementation of the UCPD would help address two of the issues with energy comparison tools identified in the Section above, namely: The misleading language used to provide consumers with a choice of which presentation to pick; and the lack of transparency about commission arrangements.

In spite of this legislation, however, there may be scope for further EU action to address this area.

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[218] In one such case, some comparison websites were found to be hiding the best deals from consumers by concealing tariffs from suppliers that did not pay these websites a commission. "*Protecting consumers: Making energy price comparison websites transparent*" (2015) UK House of Commons, Energy and Climate Change Committee, http://www.publications.parliament.uk/pa/cm201415/cmselect/cmenergy/899/899.pdf.

[219] Articles 6 and 7, in particular.

Firstly, because the UCPD is a cross-sectorial and principle-based piece of legislation, its provisions may not address all of the problems we observe in comparison tools. For example, whilst the UCPD states that comparison tools should not mislead consumers, it does not oblige them to be effective, impartial or useful to the consumer, nor does it require comparison tools to cover an entire market. A comparison tool that only displayed biased rankings would be in compliance with the UCPD as long as it clearly stated that this was the case.

Secondly, Member States may have difficulties in interpreting the provisions of the UCPD – as well as the 13 other pieces of legislation and official guidance that may apply (Box 2) – and relating this body of legislation to energy comparison tools in particular. Clearer provisions could therefore improve implementation.

Box 2: List of applicable legislation and official guidance documents

- Directive 2005/29/EC (Unfair Commercial Practices Directive)
- SEC(2009) 1666 (Guidance on Unfair Commercial Practices Directive)
- Directive 2011/83/EU (Consumer Rights Directive)
- Guidance Document concerning Directive 2011/83/EU (Guidance on Consumer Rights Directive)
- Directive 2006/114/EC (Misleading and Comparative Advertising Directive)
- Directive 2000/31/EC (E-Commerce Directive)
- Directive 98/6/EC (Price Indication Directive)
- Council Directive 93/13/EEC (Unfair Contract Terms Directive)
- Directive 2002/22/EC (Citizens' Rights Directive)
- Directive 2014/92/EU (Payment Accounts Directive)
- Regulation (EC) No 1008/2008 (Air Services Regulation)
- Directive 2009/72/EC (Electricity Directive)
- Directive 2009/73/EC (Gas Directive)
- Directive 2008/48/EC (Consumer Credit Directive)
- Directive 2007/64/EC (Payment Services Directive)
- Directive 2002/65/EC (Distance Marketing of Consumer Financial Services Directive)

Finally, whereas the UCPD and most other applicable consumer protection legislation only applies to commercial comparison tools, there is also a need to ensure the quality of comparison tools operated by national authorities and non-profit organizations.

As for the Third Package, consumer bills and pre-contractual information formed the basis of consumer comparability at the time of its drafting, as consumers would manually measure up individual offers against their current supply contract. The legislation therefore addressed these points in order to promote consumer interests. Since then, the use of online websites for comparison as well as marketing purposes has risen significantly across the EU, challenging the relevance of the sector-specific energy *acquis*, which does not address comparison tools at all.

7.5.4. *Presentation of the options*

Option 0+ (Non-regulatory approach): Cross-sectorial Commission guidance addressing the applicability of the Unfair Commercial Practices Directive to commercially operated comparison tools

The Unfair Commercial Practices Directive expressly prohibits activities that materially distort the consumer’s economic behaviour to the point where their ability to make an informed decision is impaired. This has implications for the following issues relevant to energy comparison tools, *inter alia*:

- Identification of advertising and sponsored results;
- Criteria for ranking;
- The disclosure of relationship with suppliers (assessed on a case-by-case basis);
- Displaying the same information for all products.

Building on the principles of reliability and impartiality endorsed by the Multi-Stakeholder Dialogue on Comparison Tools, the Commission has therefore very recently published updated guidance on how to apply the Directive to comparison tools in all sectors[220].

In addition, various other cross-sectorial consumer protection Directives require the disclosure of price and product data sourcing[221]. Stronger enforcement of the existing *acquis* therefore has significant potential to address the shortcomings addressed above. Accordingly, a 2013 Commission study on comparison tools found that the "[e]*nforcement of existing legal instruments appears to be first a priority*"[222].

14 different EU legal instruments and guidance documents may currently apply to comparison tools, depending on their ownership characteristics and which consumer sector they operate in. This means that both consumers and comparison tool operators are unlikely to be fully familiar with their respective rights and obligations. Further consolidated guidance can be considered here, too.

Option 1: Legislation to ensure every Member State has at least one 'certified' comparison tool that complies with pre-specified criteria on reliability and impartiality

Under this option, a designated national authority would certify energy comparison tool websites that meet certain criteria for reliability with some form of 'trustmark' as part of a voluntary scheme.

These criteria would include: impartiality; quality and accuracy of information; type of information/characteristics to be compared; transparency on the criteria used for comparisons; transparency on ranking methodologies; transparency on funding; and (near) complete coverage of the market. As these criteria would be based on recommendations contained in the Council of European Energy Regulator's 'Guidelines of Good Practice on Price Comparison Tools', they would be a product of the expert opinion of EU NRAs, as well as an extensive public consultation process[223].This sector-specific approach would plug gaps in the existing legislation, and was recently also taken to improve comparison tools in the banking sector with the 2014 Payment Account Directive.

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[220] See updated Guidance on the UCPD, http://ec.europa.eu/consumers/consumer_rights/unfair-trade/comparison-tools/index_en.htm.

[221] "*Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools"* (2013) European Commission, pp. 289.

[222] *"Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools"* (2013) European Commission, pp. 287.

[223] "*Guidelines of Good Practice on Price Comparison Tools*",(2012) CEER, Ref: C12-CEM-54-03, http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab3/C12-CEM-54-03_GGP-PCT_09Jul2012.pdf.

Box 3: Fourteen CEER recommendations for comparison tools

Independence: Comparison Tools in the energy sector should be independent from energy supply companies (1), National Regulatory Authorities (NRAs) should maintain a role by assisting self-regulation, establishing accreditation/regulation or by creating Comparison Tools (2).

Transparency: Comparison Tools should disclose the way they operate, their funding and their owners/shareholders (3).

Exhaustiveness: All prices and products available for the totality of customers should be shown as a first step. If not possible, the Comparison Tool should clearly state this before showing results. After the initial search, the option to filter results should be offered to the customer (4)

Clarity and Comprehensibility: Costs should always be presented in a way that is clearly understood by the majority of customers, such as total cost on a yearly basis or unit kWh-price including amount and duration of discounts and whether prices are an estimation based on historic or estimated consumption (5). Fundamental characteristics of all products, for example fixed price products, floating price products or regulated end user prices, should be presented on the first page of the result screen. This differentiation should be easily visible to the customer. Explanations of the different types of offers should be available to help the customer understand their options (6). The price Comparison Tool should offer information on additional products and services, if the customer wishes to use that information to help choose the best offer for them (7).

Correctness and Accuracy: Price information used in the comparison should be updated as often as necessary to correctly reflect prices available on the market (8).

User Friendliness: The user should be offered help through default consumption patterns or, preferably, a tool that calculates the approximate consumption, based on the amount of the last bill or on the basis of other information available to the user (9).

Accessibility: To ensure an inclusive service at least one additional communication channel (other than the Internet) for getting a price comparison should be provided free of charge or at minimal cost (10). Online Comparison Tools should be implemented in line with the Web Accessibility Guidelines (WCAG) and should ensure that there are no barriers to overcome to access the comparison (11).

Customer Empowerment: Where the Comparison Tool is run by an NRA/public body they should promote the service to customers. Where the NRA/public body is regulating/accrediting/actively monitoring privately run Comparison Tools they should consider establishing a marker or logo (12). Comparison Tool providers should provide background information on market functioning and market issues if the customer wants this information or provide links to useful independent sources of information (13). Information provided to customers should be clearly written and presented using consistent or standardised terms and language (14).

The main administrative costs would fall upon national competent authorities who would be charged with developing accreditation systems, monitoring compliance, and imposing sanctions. However, the legislation would allow costs to be charged to website operators seeking accreditation under this scheme. Such costs may be covered by, for example, increased sales at the level of an accredited (and thus trustworthy) comparison tool.

In Member States where comparison tools are not widely used, it may be difficult to find one that meets the criteria for certification. The legislation would therefore allow a public authority such as the NRA to establish a comparison tool conforming to the certification criteria.

However in more mature markets, existing providers are likely to be willing and able to fulfil accreditation requirements in order to gain further recognition in the market and strengthen their reputation with consumers.

Option 2: Legislation to ensure every Member State appoints an independent body to provide a comparison tool that serves the consumer interest

Examples of such independent bodies could include NRAs, consumer authorities, or independent consumer groups. The establishment and funding of such comparison tools would be left to the discretion of the Member State, however the comparison tool must conform to the same certification criteria put forward in Option 1 to ensure its reliability.

7.5.5. *Comparison of the options*

This Section compares the costs and benefits of each of the Options presented above in a semi-quantitative manner.

In general, the costs of implementing each of the above measures can be estimated to a reasonably certain degree using tools such as the standard cost model for estimating administrative costs[224]. However, no data or methodology exists to accurately quantify all the benefits of the measures in terms of direct benefits to consumer (consumer surplus) or general competition. As such, this Section draws on behavioural experiments from a controlled environment to evaluate the impact of some policy options on consumer decision-making. Where appropriate, it aims to illustrate the possible direct benefit to consumers assuming certain conditions. It also highlights important qualitative evidence from stakeholders that policymakers should also incorporate into their analysis of costs and benefits.

Option 0+: Cross-sectorial Commission guidance addressing the applicability of the Unfair Commercial Practices Directive to commercially operated comparison tools

The cross-sectorial approach addresses shortcomings in commercial comparison tools of all varieties, and minimizes the proliferation of sector-specific legislation. It helps national authorities and comparison tool operators understand the relevant EU legislation, addressing any possible cases of non-compliance. It also leads to a lighter administrative impact in the Member States.

In spite of these considerations, **it is unlikely that Option 0+ would most effectively address the problem of poor consumer engagement**.

Whereas stronger enforcement of the existing *acquis* has significant potential to address the shortcomings identified above, the existing *acquis* does not oblige comparison tools to be fully impartial, nor does it oblige existing comparison tools to cover (almost) the whole market in a given Member State. It does not apply to non-profit comparison tools, and better enforcement alone would not be as effective in boosting consumer confidence as a proactive accreditation scheme. Moreover, this option would not ensure that all EU consumers have access to a certified comparison tool – an aspect that is highly desirable given the important role comparison tools play in engaging energy consumers and the current disparity in the coverage of energy by comparison tools in various Member States (Table 1).

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[224] http://ec.europa.eu/smart-regulation/guidelines/tool_53_en.htm

It is unlikely that voluntary cooperation between Member States would address this problem, as it is domestic in nature with no common gains to be had through supra-national coordination.

Accordingly, NRAs, ombudsmen, consumer groups, and even industry associations representing electricity and gas suppliers all support firmer action than Option 0+ proposes. Indeed, the only major stakeholder that partially supports the soft-law approach embodied in Option 0+ appears to be the European Parliament's Committee on the Internal Market and Consumer Protection. But even here, the Committee also calls for EU-wide access to an energy comparison tool – something that cannot be ensure without legislative changes.

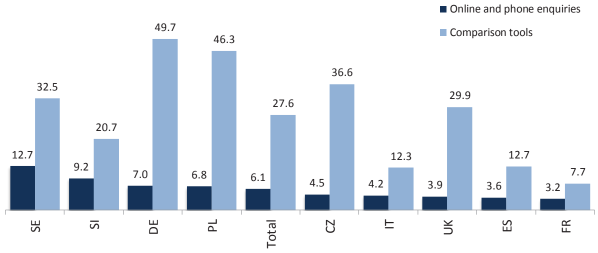
There are **no implementation costs** associated with Option 0+.

Option 1: Legislation to ensure every Member State has at least one 'certified' comparison tool that complies with pre-specified criteria on reliability and impartiality

The **economic benefits** of Option 1 will primarily be indirect, and come in terms of greater competition (lower prices, higher standards of service and a broader variety of products on the market). Comparison tools reduce the cost of comparing the market for consumers and help to lower information asymmetries[225]. Indeed, a behavioural experiment showed that comparison tools increased the number of cheaper offers consumers were able to identify by between two and twenty times (depending on the Member State) compared with contacting individual providers directly. Given that insufficient financial gain is the main consideration for not switching, this option should therefore help to reduce consumer 'stickiness' and create a more level playing field for suppliers.

[225] Comparison tool users surveyed for a recent EU study reported that they used these tools because they offered them a quick way to compare prices (mentioned by 69%) and allowed them to find the cheapest price (68%). Vast majorities of consumers agreed that price comparison websites are the quickest way to compare prices (in total, 90% agreed), are easy to use (87%), and are useful to find out information about specific products/prices (84%). "*Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools*" (2013) European Commission,

Figure 2: Number of cheaper offers found (mean) – Contacting providers vs. using comparison tools



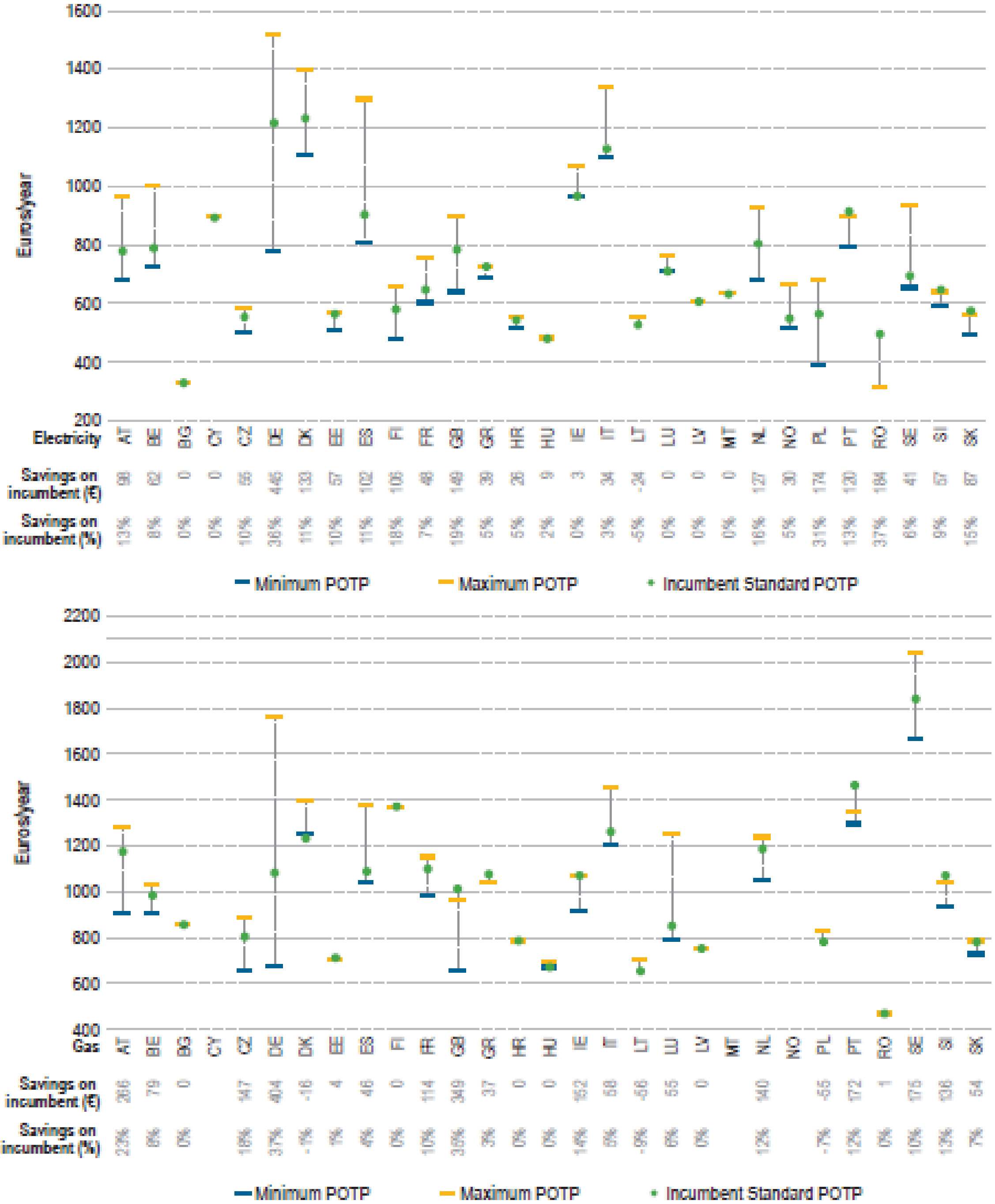
Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

In addition, Option 1 will directly result in **greater consumer surplus**. Consumer protection will be strengthened as suppliers and companies managing comparison tools will be required to improve levels of transparency. For example, tools will not be restricted to displaying the offers that are of greatest financial interest to either party. Customer mobility through transparent publication of all offers will be improved, as will customer trust through certification.

For this reason, the vast majority of consumers prefer comparison tools with third party verification. In a behavioural test carried out within the recent study on price comparison tools 78% of respondents chose an energy comparison tool that included third party verification over 22% that chose tools with no verification[226].

[226] 12,000 respondents from 15 Member States: CZ, DE, DK, FR, GR, HR, HU, IT, LV, NL, PL, UK, RO, SE, SI. The experiment tested (a) consumer choice of a comparison tool at the initial online search stage using a mock search engine; (b) consumer choice of a comparison tool from a short list; and, (c) consumer choice of a product or service on an individual comparison tool. The experiment was framed for the electricity sector and travel sector (hotels). "*Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools*" (2013) European Commission, p. 205.

Figure 3: POTP price spread and annual savings available from switching from the incumbent standard offer



Source: ACER Retail Database (November–December 2014) and ACER calculations

Whilst the economic benefits of Option 1 in terms of increased competition cannot be quantified[227], one dimension of consumer surplus – the direct financial benefits to

[227] EU retail markets differ on too many dimensions to make a comparative approach reliable. And too many factors affect key retail indicators to make the results of a longitudinal study into comparison tools reliable.

consumers of easier and more effective switching as a result of this measure – can be estimated using the following assumptions.

If we assume that:

- The 14 Member States that already have accreditation schemes or at least one government-operated comparison tool (AT, BE, DK, ES, FI, FR, IE, IT, LU, PL, PT, SE, SI, UK) would see no additional benefits from this intervention because they already fulfil its requirements[228];
- The average switching rates for electricity and gas in each of the other Member States (BG, CZ, DE, EE, EL, HR, HU, LT, LV, NL, RO, SK)[229] increased by 0.1% as a result of the intervention[230];
- The annual financial benefit of switching in these Member States amounts to the difference in price between the incumbent's standard offer and the cheapest offer in the capital city (Figure 3 above).[231];
- The financial advantage of switching as a result of these measures persists for four years[232];
- Apart from increasing the switching rate, there were no other benefits of this intervention in term of improving the ability of switching customers to identify a better offer[233];
- All EU households within each Member State are able to benefit from these changes equally in relative terms[234];
- A discount rate of 4% for the consumer benefits year on year;

then Option 1 would result in an increase in consumer surplus **of between 27.8 million euros and 98.3 million euros annually** (depending on the year of implementation), and **843 million euros in total for the period 2020-2030**. The main **implementation costs** would fall upon national competent authorities who would be charged with developing

228 This is a conservative assumption, as it may be that the certification criteria put in place by Option 1 could improve the functioning of some existing certification schemes and government-run comparison tools.

229 CY and MT were not included in this analysis.

230 Reflecting the increased consumer confidence in comparison tools, which greatly reduce the costs of comparing the market. 27% of consumers surveyed strongly agreed, and 48% somewhat agreed, that they trusted comparison tools more when they were affiliated with a third-party verification scheme. And when respondents in a behavioural experiment were offered the choice between energy comparison tools that carried no verification and ones that did, the sites that carried verification schemes were selected 3.5 times more often than the ones that did not. "*Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools*" (2013) European Commission, pp. 191, 205.

231 This proxy correlates well with the results of a mystery shopping exercise in which respondents were asked to report the actual annual savings they would benefit from if they moved to the cheapest electricity tariff they were able to find. "*Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU*" (2016) European Commission.

232 A conservative assumption given the implied average time between switches is upwards of 15.5 years for electricity consumers and 18 years for gas consumers.

233 A conservative assumption in light of Figure 2.

234 In reality, households will react differently depending on consumers' needs, skills, motivations, interests, lifestyle, and access to resources such as accurate online comparison tools. However, we have no reliable data to quantify these differences in this specific context.

accreditation systems or comparison websites, monitoring compliance, and imposing sanctions.

Box 4: The costs of Elpriskollen.se - the Swedish NRA's comparison tool[235]

Initial investment (2008): 1,000,000 SEK (EUR 107,000)

IT system upgrade (2014): 280,000 SEK (EUR 29,400)

Website upgrade (2015): 600,000 SEK (EUR 63,600)

Annual running costs:

License: 28,000 SEK (EUR 2,996)

Servers and storage: 72,000 SEK (EUR 7704)

Application support and CGI: 150,000 SEK (EUR 16,050)

1 to 1.7 fulltime positions, depending on the year: EUR 66,768 - EUR 113,506

This equates to c. EUR 110,000 in start-up costs and EUR 105,143 - EUR 151,881 in running costs, factoring in the annualized costs of periodic website and IT system upgrades.

Box 5: The costs of operating Ofgem's confidence code for comparison tools[236]

The UK currently has 12 websites that are accredited by a full-time, 3-person team at Ofgem. This small team deals with ad hoc stakeholder engagements associated with the day-to-day operation of the confidence code, as well as performing continuous internal audits of accredited websites throughout the year.

In addition, each accredited website undergoes an external audit every year by an external consultant (19 hours per site), and every new site registered undergoes a substantial external audit (70 hours per site).

This equates to around EUR 214,335 in annual running costs, assuming one new site is accredited each year

Assuming:

- All Member States currently without any comparison tools (EE, BG, LV, LT, and RO) set up a state-run comparison tool to fulfil their obligations under Option 1;
- The costs of each of these comparison websites for electricity and gas is 50% higher than the cost of the Swedish NRA's electricity price comparison website, which deals with electricity alone (Box 4)[237];

[235] Labour costs assume 2,080 work hours per man-year at EUR 32.10 for professionals, as per the standard cost model.

[236] Labour costs assume 2,080 work hours per man-year at EUR 41.50 for managers, EUR 32.10 for professionals and EUR 23.50 for technicians or associate professionals, as per the standard cost model. Calculations assume that Ofgem's confidence code team consists of one of each of the aforementioned categories, and that external consultants charge at the rate of managers.

- All other Member States that would have to make changes under this option (CZ, DE, EL, HR, HU, NL, SK) set up an accreditation scheme to fulfil their obligations;
- The costs of the UK's accreditation scheme for energy comparison tools (Box 5) can help us estimate the cost of accreditation schemes in these Member States;
- The costs of administering accreditation schemes is directly proportional to the size of the market in terms of households[238];
- The cost of voluntary accreditation schemes to comparison tools is zero[239];
- A discount rate of 4% for the consumer benefits year on year;

then Option 1 would result in **start-up costs of 802,500** euros **running costs of between 1 million euros and 1.63 million euros annually** (depending on the year of implementation), and a **total cost of between 13.3 euros and 16.5 million euros for the period 2020-2030**.

As regards stakeholder views, Option 1 would likely enjoy broad support amongst all stakeholder groups. Whilst many stakeholders support the principle that comparison tools should be independent and accurate without explicitly addressing the means of achieving this, some – notably including industry groups and the European Parliament's ITRE Committee, and the Committee of the Regions – explicitly call for certification.

Option 2: Legislation to ensure every Member State appoints an independent body to provide a comparison tool that serves the consumer interest

As with Option 1, Option 2 would likely result in indirect and unquantifiable **economic benefits** in terms of greater competition. It would also result in **greater consumer surplus**.

It would ensure EU-wide access to comparison tools free from any commercial interest that could affect their impartiality. It would also have the additional benefits that national authorities would be able to censure suppliers by removing their offers from the comparison tool, there would be no obligation on the private sector, and no risk of claims of favouritism in a certification process.

When asked which organizations would be the most appropriate to run comparison tools, 51% of comparison tool users thought that they should be run by consumer organisations. 13% selected a national authority or regulator as the most suitable organisation, and 8% preferred to entrust this task to a private organisation[240]. Given these results, one might expect Option 2 to lead to greater levels of consumer trust than Option 1.

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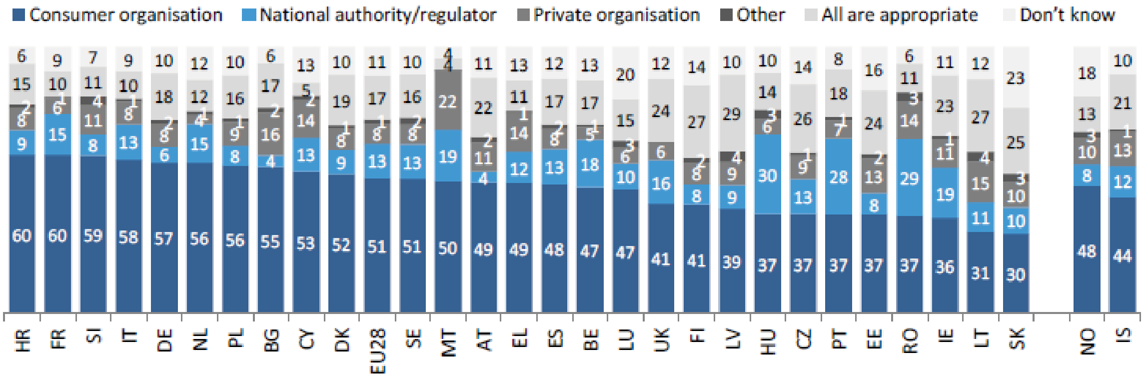
[237] This is a conservative estimate given the significant labour cost differences between SE and these Member States that would make setting up and operating a comparison website cheaper in other Member States.

[238] A conservative estimate, given that the UK appears to have a disproportionately large number of comparison tools for the size of its market (Table 1).

[239] As the scheme is voluntary, comparison tools can be expected to only to make the changes necessary to qualify for accreditation if they judged this would be in their long-term financial interest anyway.

[240] "*Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools*" (2013) European Commission, p. 203.

Figure 4: Most appropriate organisation to run comparison tools (by country)[241]



"*Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools*" (2013) European Commission

If we assume that:

- The average switching rates for electricity and gas in each of the 13 Member States at least one government-operated comparison tool (BG, CZ, DE, EE, EL, HR, HU, IE LT, LV, NL, RO, SK)[242] increased by 0.13% as a result of the intervention – 30% more than option one[243];
- The annual financial benefit of switching in these Member States amounts to the difference in price between the incumbent's standard offer and the cheapest offer in the capital city (Figure 3 above)[244];
- The financial advantage of switching as a result of these measures persists for four years[245];
- Apart from increasing the switching rate, there were no other benefits of this intervention in term of improving the ability of switching customers to identify a better offer[246];
- All EU households within each Member State are able to benefit from these changes equally in relative terms[247];
- A discount rate of 4% for the consumer benefits year on year;

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241 Question: "Comparison tools can be run by different types of organisations. Among the following organisations, which one do you think is the most appropriate?" '.

242 CY and MT were not included in this analysis.

243 Reflecting Figure 4. However, this estimate is highly uncertain in light of the fact that it assumes that Member States would provide sufficient resources for the development of publicly run comparison tools to match the quality of offerings from the private sector.

244 This proxy correlates well with the results of a mystery shopping exercise in which respondents were asked to report the actual annual savings they would benefit from if they moved to the cheapest electricity tariff they were able to find. "*Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU*" (2016) European Commission.

245 A conservative assumption given the implied average time between switches is upwards of 15.5 years for electricity consumers and 18 years for gas consumers.

246 A conservative assumption in light of Figure 2.

247 In reality, households will react differently depending on consumers' needs, skills, motivations, interests, lifestyle, and access to resources such as accurate online comparison tools. However, we have no reliable data to quantify these differences in this specific context.

then Option 2 would result in an increase in consumer surplus **of between 56 million euros and 128 million euros annually** (depending on the year of implementation), and **1.1 billion euro in total for the period 2020-2030**. However, there is a **greater degree of uncertainty in these figures** when compared with the workings for Options 1, in light of possible variance in the effectiveness of such publicly-run comparison tools.

The main **implementation costs** would fall upon national authorities who would be charged with developing and managing energy comparison websites[248]. Privately-run comparison sites may also lose market share to comparison tools run by a government-funded body, although these impacts are impossible to estimate.

Assuming:

- All 13 Member States without a state-run comparison tool (BG, CZ, DE, EE, EL, HR, HU, IE LT, LV, NL, RO, SK) set one up to fulfil their obligations under Option 2;
- The costs of each of these comparison websites for electricity and gas is 50% higher than the cost of the Swedish NRA's electricity price comparison website, which deals with electricity alone (Box 5)[249];
- A discount rate of 4% year on year;

then Option 2 would result in **start-up costs of 2.09 million euros**, **running costs of between EUR 1.36 million and EUR 2.96 million euros annually** (depending on the year of implementation), and a **total cost of between 20.6 million euros and 28.9 million euros for the period 2020-2030**.

As regards stakeholder views, Option 2 may not enjoy broad support amongst all stakeholder groups and Member States. Whilst all stakeholders emphasize the independence of comparison tools, and some explicitly support certification (Option 1), none have voiced their exclusive support for a publicly run and funded energy comparison tools.

Conclusion

Option 1 is the preferred option. By proportionately updating the existing acquis, establishing a mechanism to proactively build consumer trust, and ensuring all EU consumers have access to a comparison tool, it strikes the best balance between consumer welfare and administrative impact. It also gives Member States control over whether they feel a certification scheme or a publicly-run comparison tool best ensures consumer engagement in their markets.

Box 1: Impacts on different groups of consumers

The benefits of the measures contained in the preferred option (Option 1), described in detail in the preceding pages, accrue predominantly to consumers who are engaged in the market, and in particular those who compare offers using the Internet. Whilst reliable comparison tools will also increase consumer

[248] The costs to suppliers in terms of notifying such sites of their is not considered significant.

[249] This is a conservative estimate given the significant labour cost differences between SE and these Member States that would make setting up and operating a comparison website cheaper in other Member States.

engagement levels, and whilst the increased competition engendered by comparison tools will lead to more competitive offers on the market, disengaged consumers and consumers who do not use the Internet, including consumers who may be vulnerable, will not reap as many direct benefits from this policy intervention.

7.5.6. *Subsidiarity*

Consumers are not taking full advantage of competition on energy markets due, in part, to obstacles to switching. Well designed and implemented consumer policies with a European dimension can enable consumers to make informed choices that reward competition, and support the goal of sustainable and resource-efficient growth, whilst taking account of the needs of all consumers. Increasing confidence and ensuring that unfair trading practices do not bring a competitive advantage will also have a positive impact in terms of stimulating growth.

Comparison websites are an effective means of reducing search costs for consumers and presenting them with accurate price and market information. Although they have become increasingly important in recent years, the majority of comparison websites are operated for profit, leading to situations where their impartiality and the consumer interest may not be ensured. Recent reports of unscrupulous practices have damaged consumer trust in comparison websites, suggesting the need to boost consumer confidence in such tools.

The options here revolve around improving the accessibility and reliability of comparison websites, both commercial and not-for-profit, through improved legislative guidance, certification schemes and/or differing obligations on Member States to ensure the availability of such websites. Similar legislative provisions on comparison tools already exist in other sectorial legislation (i.e. financial sector with the 2014 Payment Accounts Directive[250]).

The legal basis for the legislative options proposed (Options 1 and 2) is therefore likely to be Article 114 TFEU. This allows for the adoption of *"measures for the approximation of the provisions laid down by law, regulation or administrative action in Member States which have as their object the establishment and functioning of the internal market"*. In doing this, in accordance with Article 169 TFEU, the Commission will aim at ensuring a high level of consumer protection.

Without EU action, the identified problems related to the lack of an EU-wide market will continue to lead to consumer detriment.

Option 0+
These options would fulfil the subsidiarity principle as they do not involve legislative change and the subsidiarity of the existing legislation has been assessed previously.

However, consumer protection will continue to be compromised as consumers will not have the assurance of comparison tool independence or of full transparency of all offers

[250] Directive 2014/92/EU of the European Parliament and of the Council of 23 July 2014 on the comparability of fees related to payment accounts, payment account switching and access to payment accounts with basic features. Text with EEA relevance.

available on the market. This is because of shortcomings inherent in the existing legislation.

Option 0+ would therefore not meet the proportionality principle as it would not achieve the objective of the Article of the Treaty taken as their legal basis – the establishment and functioning of the internal market.

Option 1
The principles of subsidiarity and proportionality would be best met through this Option as it would concretely improve the functioning of the internal market and reduce levels of consumer detriment, whilst leaving national authorities broad flexibility to tailor measures to the characteristics of their markets and their available resources.

Option 2
The principles of subsidiarity and proportionality may not be respected in this Option as it may be excessive in terms of the implied impact on certain Member State authorities who would need to establish an independent body to provide a comparison tool service.

Moreover, it is not clear that customer mobility or consumer protection would improve with the introduction of such a body in all Member States as the reliability and user-friendliness of at least some private sector comparison tools may already be of a high standard.

7.5.7. *Stakeholders' opinions*

Public Consultation
When asked to identify key factors influencing switching rates, 110 out of 237 respondents to the Commission's Consultation on the Retail Energy Market[251] stated that prices and tariffs were too difficult to compare due to a lack of tools and/or due to contractual conditions.

178 out of 237 agreed that ensuring the availability of web-based price comparison tools would increase consumers' interest in comparing offers and switching to a different energy supplier. 40 were neutral and 4 disagreed.

Only 32 out of 237 respondents agreed with the statement: *"There is no need to encourage switching"*. 98 disagreed and 90 were neutral.

National Regulatory Authorities
ACER has argued that having reliable web comparison tools in place (allowing comprehensive and easy ways to compare suppliers) can facilitate consumer choice and consumer engagement by addressing the perceived complexity of the switching process. It has therefore recommended that: *"To improve consumer switching behaviour and awareness further, National Regulatory Authorities (NRAs) could become more actively involved in ensuring that the prerequisites for switching, such as transparent and*

[251] Held from 22 to 17 April 2014. https://ec.europa.eu/energy/en/consultations/consultation-retail-energy-market

reliable online price comparison tools and transparent energy invoices, are properly implemented."

CEER[252] sees price comparison tools as a crucial instrument to provide information to electricity and gas customers. There are a range of routes to setting standards for comparison tools. NRAs or another public body may establish their own comparison tools or they may regulate private comparison tools. Alternatively, self-regulation by comparison tools providers may be appropriate. Whatever the route, CEER's position is that it is important that comparison tools are independent from energy supply companies, that they are accurate and that they ideally present the full range of offers available.

In 2012, following an extensive consultation process, CEER published 14 recommendations covering the following aspects of comparison tools in the energy sector: Independence; transparency; exhaustiveness; clarity and comprehensibility; correctness and accuracy; user-friendliness; accessibility; and empowering customers[253].

Ombudsmen
According to **NEON**, the National Energy Ombudsmen Network, regulators are best placed to define the criteria of transparency and reliability of price comparisons tools and to assess them. NEON insisted on referring to the 2012 CEER Guidelines of Good Practice on Price Comparison Tools and the 15 recommendations they contain[254].

Bodies in charge of providing information to consumers (single point of contact) and organisations in charge of alternative dispute resolution (or an independent ombudsman), as well as consumer associations (i.e. impartial bodies with no advertising or consumer champion role, thanks to their independence from suppliers) are according to NEON best placed to develop neutral and reliable tools. This may also be the case of private companies, as long as they do not favour certain suppliers that would fund them or with which they have special agreements. For all tools implemented, an annual auditing of the regulator would be necessary: the list of approved comparison tools and a summary of the auditing may be published and accessible online.

If the regulator sets up a price comparison tool, another authority should be responsible for carrying out auditing, even from another Member State (peer review).

Consumer Groups
BEUC believes it is essential that the consumer gets clear and independent information on different offers. Regardless of who is running the comparison website, it must be ensured that the information consumers get is impartial, up to date, accurate and provided in a user friendly way and free of charge. The comparison tool should also enable consumers to compare their current contract with new offers in an easy way.

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252 The Council of European Energy Regulators.

253 http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab3/C12-CEM-54-03_GGP-PCT_09Jul2012.pdf

254 http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab3/C12-CEM-54-03_GGP-PCT_09Jul2012.pdf

At the same time, BEUC strongly believes there should be at least one independent comparison tool for electricity and gas services in every Member State. In order to secure the success of such a comparison tool, it is paramount to secure also a legal basis for collection of price data. In addition, whilst comparison tools are increasingly used by consumers, the proliferation of comparison tools and the influence they can have on consumers' decisions have given rise to concerns about their trustworthiness.

According to BEUC, if the transparency and reliability of comparison tools is not guaranteed, if the full scale and high quality of the information they provide is not ensured or if they do not comply with existing legislation, comparison tools can become a source of consumer detriment and risk misleading and thereby undermining consumers' trust in the market[255].

According to **Citizens' Advice** (UK) comparison tools can be operated by a regulator, a consumer body or a private business that is appropriately regulated. The focus should rather be on the establishment of key principles to the effect that the sites display information in a way that is accurate, consistent, transparent, comprehensive and unbiased. The tool must have all tariff data available from all suppliers in the market and include information about termination fees, etc. The comparison should be based on the customer's actual usage.

Suppliers
In their contribution to the discussions within the Citizens' Energy Forum in 2016, **EURELECTRIC** considered that it is the task of regulators to make sure that comparison tools are neutral, do not limit innovation and do not favour any specific supplier, either directly (for example, if they collect different fees from different suppliers) or indirectly (for example, if their IT systems are not able to process all offers). EURELECTRIC and its members have repeatedly argued in favour of certifying comparison tool with e.g. a trust mark from the regulator, and stressed their full support for the Commission's initiatives to work with NRAs to develop transparency and reliability criteria for comparison tools where these do not exist yet.

Eurogas also welcomed the role that price comparison websites can play in national energy markets, and argued that consumers should have access to such price comparison services. For Eurogas, both price comparison websites operated by commercial entities as well as non-commercial bodies operated by the NRA can provide "independent" services to consumers. In order to ensure that this is the case, Eurogas supports an accreditation system for such websites. According to Eurogas, experience in Member-States such as the UK and the Netherlands suggests that price comparison websites develop over time, with private companies establishing comparison services.

Whatever approach is adopted, Eurogas states that the funding of these sites should be transparent. Regulation should be proportionate and would benefit from referring to the

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255 http://www.beuc.eu/publications/beuc-x-2015-068_mst_building_a_consumer-centric_energy_union.pdf

2012 CEER Guidelines of Good Practice on Price Comparison Tools[256]. Moreover, for recommendations and best practices on price comparison tools, reference should be made to the 2012 Report of the CEF Working Group on Transparency in EU Retail Energy Markets[257].

The European Parliament
In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the Parliament's **Committee on Industry, Research and Energy (ITRE)**: "Recommends developing guidelines for price comparison tools to ensure that consumers can access independent, up-to-date and understandable comparison tools; believes Member States should consider developing accreditation schemes covering all price comparison tools, in line with CEER guidelines."

In addition, ITRE: "*Recommends the creation of new platforms to serve as independent* [comparison tools] *to provide greater clarity to consumers on billing; recommends that such independent platforms provide consumers with information on the percentage share of energy sources used and the different taxes, levies and add-ons contained in energy tariffs in a comparable way to empower the consumer to easily seek more suitable offers in terms of price, quality and sustainability; suggests that this role could be assumed by existing bodies such as national energy departments, regulators or consumer organisations; recommends the development of at least one such independent price comparison tool per Member State.*"

In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the Parliament's **Committee on the Internal Market and Consumer Protection (IMCO)** called on the Commission: *"to ensure the implementation of the Unfair Commercial Practices Directive and for better cooperation between national authorities of Member States investigating such practices"*. It also welcomed "*the Commission's intention to consider incorporating laws specifically concerning energy into the Annex to the Regulation on Consumer Protection Cooperation*", although this measure was not eventually pursued by the Commission.

IMCO also called for: "*European Union guidelines on independent, up-to-date and easy-to-use price comparison tools, in particular to improve transparency, reliability, and competition between all market players and to make it accessible and easier for consumers to compare offers including types of contracts, prices and types of energy sources.*" It finally supported: *"access for all consumers to at least one price comparison tool for energy services."*

The Committee of the Regions
In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the **Committee of the Regions** supports the idea of ensuring that each consumer has access to at least one independent and verified

[256] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab3/C12-CEM-54-03_GGP-PCT_09Jul2012.pdf
[257] https://ec.europa.eu/energy/sites/ener/files/documents/2012111314_citizen_forum_meeting_working_group_report.pdf

comparison tool. According to the Committee, these comparators must be clear, comprehensive, trustworthy and independent, easy to use and free of charge. They should allow existing contracts to be compared with offers available on the market. Whereas suppliers tend to diversify their offers by including services in energy supply contracts, comparison tools must make it possible to compare the different "packages" on offer, while at the same time enabling the "supply" element of the various packages to be compared on its own.

7.6. Improving billing information

7.6.1. *Summary table*

Objective: Ensuring that all consumer bills prominently display a minimum set of information that is essential to actively participating in the market.			
Option: 0	Option 0+	Option 1	Option 2
BAU/Stronger enforcement	Commission recommendation on billing information	More detailed legal requirements on the key information to be included in bills	A fully standardized 'comparability box' in bills
Pros: - 77% of energy consumers agree or strongly agree that bills are "easy and clear to understand". - Allows 'natural experiments' and other innovation on the design of billing information to be developed by Member State. - Recent (2014) transposition of the EED means premature to address information on energy consumption and costs.	Pros: - Low administrative impact - Gives Member State significant flexibility to adapt their requirements to national conditions. - Allows best practices to further develop.	Pros: - Ensures that the minimum baseline of existing practices is clarified and raised. - Allows best practices to further develop, albeit less than Option 0. - Improves comparability and portability of information. - Ensures consumers can easily find the information elements needed to facilitate switching. - Bill design left free to innovation.	Pros: - Highest legal clarity and comparability of offers and bills. - A level playing field for all consumers and suppliers across the EU. - Very little leeway for suppliers to differently interpret the legislation with regards to the presentation of information. - Ensures consumers can easily find the information elements needed to facilitate switching.
Cons: - Poor consumer awareness of market-relevant information can be expected to continue. - Does not respond to stakeholder feedback on need to ensure minimum standards.	Cons: - A recommendation is unenforceable and may be ignored by Member State/utilities. - Poor consumer awareness of market-relevant information can be expected to continue. - Does not respond to stakeholder feedback on need to ensure minimum standards.	Cons: - Limits innovation around certain bill elements. - Remaining leeway in interpreting legal articles may lead to implementation and enforcement difficulties.	Cons: - Challenging to devise standard presentation which can accommodate differences between national markets. - Highest administrative impact. - Prescriptive approach prevents beneficial innovation. - Difficult to adapt bills to evolving technologies and consumer preferences.
Most suitable option(s): Option 1 is the preferred option as it likely to leads to significant economic benefits and increased consumer surplus without significant administrative costs or the risk of overly-prescriptive legislation at the EU level.			

7.6.2. *Description of the baseline*

The evidence presented in this Annex draws extensively on survey data, as well as data from a mystery shopping exercise. The aim of the mystery shopping exercise was to replicate, as closely as possible, real consumers' experiences across 10 Member States[258] selected to cover North, West, South and East Europe countries. A total of 4,000 evaluations were completed between 11 December 2014 and 18 March 2015[259]. Whilst data from the mystery shopping exercise is non-exhaustive, the methodology enables the controlled sampling of a very large topic area[260], as well as providing insights that would not be apparent in a desktop evaluation of legislation and bills. Using a behavioural research approach rather than a traditional survey allowed us to identify what people actually do, rather than what they say they do.

Energy bills and annual statements be they paper or digital, are the most likely regular communications from suppliers to be noticed and read by consumers. They are therefore an important means through which consumers get information on their interaction with the market. As well as data on consumption and costs, they can also convey a host of other material which helps consumers to compare their current deal with other offers – the name and duration of their contract, for example.

The Electricity and Gas Directives contain the following key provisions related to metering and billing:

- Article 3 Billing and promotional material
    - 3(3) Access to comparable and transparent supply options (Electricity only)
    - 3(5)/3(6) Access to consumption data
    - 3(9) Disclosure of the overall fuel mix and environmental impact of the supplier (Electricity only)
- Annex I Consumer protection
    - 1.c) The transparency of applicable prices and tariffs
    - 1.d) Consumer payment methods
    - 1.i) Frequency of information on consumption and costs
    - 2. Intelligent metering systems (smart meter roll-out)

In addition, The Energy Efficiency Directive contains the following key provisions:

- Article10 Billing information (in conjunction with Annex VII)
    - 10(1) Consumption based billing (information) requirement in general (incl. as regards minimum frequency)
    - 10(2) Requirements on consumption information from smart meters
    - 10(3) General information and billing requirements pertinent to costs, consumption and payment

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258 The Czech Republic, France, Germany, Italy, Lithuania, Poland, Slovenia, Spain, Sweden and the UK.

259 *"Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU"* (2016) European Commission.

260 For example, there were over 400 electricity and gas supply offers in Berlin alone in 2014 (source: ACER Database), making a comprehensive examination of all supply offers in the EU28 impracticable.

- Article 11 Cost of metering and billing information
    - 11(1) Metering and billing generally free of charges

Whereas the EU *acquis* contains a relatively small number of general measures on energy billing, all Member States have legislation with further billing requirements. For example, UK electricity and gas suppliers must follow over 70 pages of rules on the information in bills as part of their current licensing requirements. In recognition of the likelihood of being overly prescriptive at present, the UK NRA is undertaking a pilot project to improve billing in the interest of consumers.

Box 1: Select requirements for UK domestic energy bills[261]

The following information must be grouped together, in a box, distinct from other information and included on page one of the Bill:
- The standardised title “Could you pay less?”
- Information on cheaper tariffs offered by the supplier and the savings available if the consumer were to switch.
- A Personal Projection* for the consumer's current tariff.
- A signpost to further tariff information.
- A standardised switching reminder “Remember – it might be worth thinking about switching your tariff or supplier”.

The following information must be grouped together and included on page two of the Bill, in a box, distinct from other information, in the following order:
- The standardised title “About Your Tariff”.
- The name of the customer's fuel, current tariff, payment method, any applicable tariff end date, exit fees and the customer's personalised usage in the last 12 months.

The following information must be provided anywhere on a bill:
- The standardised title “About Your TCR”**.
- The TCR for the customer's current tariff.
- A signpost to where to find independent advice on switching supplier.

* The Personal Projection is a standardised methodology that uses a consumer's actual or estimated consumption to estimate their projected cost for a particular tariff for the next year.

** The TCR or 'Tariff Comparison Rate' is used to assist consumers to make an initial comparison of alternative tariffs. It is similar in nature to the Annual Percentage Rate used to describe savings, loan and credit agreements.

261 "*The Retail Market Review – Final domestic proposals Consultation on policy effect and draft licence conditions*", (2013) Ofgem, pp. 71-108, 130-163 https://www.ofgem.gov.uk/sites/default/files/docs/2013/03/the-retail-market-review---final-domestic-proposals.pdf. See also Gas and Electricity Markets Authority, 'Standard conditions of electricity supply licence' https://epr.ofgem.gov.uk//Content/Documents/Electricity%20Supply%20Standard%20Licence%20Conditions%20Consolidated%20-%20Current%20Version.pdf

Table 1 below presents an overview of billing practices and regulation per country. There is a large variation in how countries choose to approach the subject, in particular with regards to the extent to which the content of bills is specifically defined in national legislation. Three broad approaches can be identified:

- Highly prescriptive (HP) approaches relying on legal instruments or resolutions, which request a large amount of detail and/or give very specific instructions on what information to provide in electricity bills.
- Legislation which specifies the main information (MI) that must be included in bills, which is subsequently reinforced by guidance from the regulator (in terms of mandatory information and format, or best practice guidance).
- Legislation that specifies the main information, but leaves electricity providers broad freedom (BF) to communicate this within their own format.

In the following table, billing practices in each country are described, noting what are considered to be a highly prescriptive approach (HP), an approach enforcing communication of main information (MI) and, finally, an approach that allows broad freedom (BF).

Table 1: Billing practices and regulation per country[262]

Austria (MI)	Article 81 of EIWOG specifies which information should be presented on the electricity bill. This provision is further detailed by ordinances from the regulator, in which suggestions are given as to how to present the mandatory information, including the energy sources breakdown and the price components. The contents of the documents (e.g. electricity bill, contract, etc.) are detailed not only in the Electricity Act, but also in the Renewable Energy Act, the System Charges Order, the Electricity Duty Act, as well as in individual Federal states legislation. The 'DAVID-VO' Ordinance (Articles 1-5) specifies the information that electricity suppliers must give to customers.
Belgium (HP)	Law April, 29th 1999 'Loi relative à l'organisation du marché de l'électricite' details the mandatory information to be present in a consumer's bill. The information to be presented in the bill is highly regulated, with 10 mandatory headings and many mandatory sub-headings which detail the information to be provided.
Bulgaria (BF)	The Bulgarian Consumer Protection Act (Art. 4, Par. 1) outlines a minimum set of requirements for information to be provided to the customer such as: (1) information on the composition, (2) the supplier's contact details, (3) the trader's complaint handling process, and 4) arrangements for payment.
Croatia (MI)	Articles 49 and 63 of the Act on Electricity Market (Official Gazette, no. 22/13, 95/15 and 102/15) regulate billing. In Croatia, regulations specify that the supplier needs to deliver an electricity bill that contains the following elements: the share of the price that is freely negotiated, the share that is regulated and fees and other charges prescribed by special regulations.
Cyprus (MI)	Article 91 (1)(d)(iv) and Article 93 (1)(j) of the Electricity Law 206(I)/2015 regulate how the consumption of electricity should be communicated to consumers. The tariffs of the main energy provider are regulated by the Cyprus Energy Regulatory Authority (CERA) and they can be found on the website of the Electricity Authority of Cyprus (EAC).
Czech Republic (DF)	Bills for electricity, gas, heat supply and related services are governed by Act nr. 458/2000 Coll. in articles 11(a) and 98a. Electricity suppliers are to publish the conditions and price of electricity supply for households and residential customers in a way that can be accessed remotely. If increasing the prices for the supply of electricity, the supplier is obliged to notify the consumer in advance. In the case of electricity and gas, outstanding charges are

[262] "*Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU*" (2016) European Commission.

	billed at least once a year.
Denmark (MI)	Regulation of billing information is implemented in Executive Order no.486 of 2007 on electricity billing. However, the Danish Energy Regulatory Authority has presented an executive order which gives consumers the possibility to receive a simplified bill. The purpose of this order is to give consumers a better understanding of the price elements and an incentive to be active on the energy market. This order was implemented in Danish law in October 2015.
Estonia (MI)	Electricity Market Act §75 stipulates the following: "the seller shall submit an invoice for the electricity consumed to the customer once a month, unless agreed otherwise with the customer". It is mandatory for suppliers to include information not just on consumption but also on emissions and waste (nuclear and oil shale) as well as dispute resolution options.
Finland (MI)	Part III, Ch. 9, 69 § of the Electricity Market Act (588/2013) outlines the legal requirements with regards to billing imposed by the electricity provider. In the bill, the provider is to include details on how the price is broken down, information on the contract's duration and which dispute-solving tools consumers have at their disposal.
France (HP)	Article 4 of the Regulation 18 April 2012 covers electricity or natural gas bills, their payment modalities and reimbursement of overpayment (i.e. bill based on an estimation of the consumption). The bill must include information on over 16 different headings. The website 'Energie info', made available by the National Energy Ombudsman, illustrates and explains this mandatory content to consumers.
Germany (MI)	The right to receive clear information on one's energy contract before signing, and to be informed in advance if any changes are made to the contract, are provided for within German law (article 41 EnWG). The EnWG (Section IV art. 40) specifies the content that should be provided to consumers on their electricity bills. The German Institute for Transparency on Energy (DIFET) produces certificates for those suppliers that provide consumer-friendly bills.
Greece (BF)	The new Code of Electricity Supply regulates the tariffs of electricity suppliers. Specifically, this code describes what must be included in the bill and how the bill must be broken down into three different elements: (1) regulated charges; (2) competitive charges or supply charges; and (2) other charges.
Hungary (HP)	*Law 2013. évi CLXXXVIII. törvény az egységes közszolgáltatói számlaképről* regulates the content of bills. The law gives actual examples of the minimal information necessary on each bill and also gives examples as to which elements may be changed or added without infraction. The law also imposes such details as fonts and font sizes and provides in its annexes a detailed example of the respective bill in its actual detail. Additionally to the law, the electricity suppliers also regularly provide a dedicated Section on how to read the electricity bill.
Ireland (MI)	Statutory instruments S.I. No. 426/2014 Part 4, Art. 6, Art. 7 and S.I. No. 463/2011, Art. 9, regulate the communication of charges and consumption information to electricity consumers in Ireland. Under Irish law, suppliers must also inform customers of upcoming price changes at least one month before a price change comes into effect.
Italy (MI)	D.Lgs 93/11 Art. 43(2); L 125/07 Art. 1(6) and Art. 1(5) legislate the communication of charges and consumption information. Consumers should be informed of the components relating to supply cost (*servizi di vendita*), network cost (*servizi di rete*), general system charges (*oneri generali di sistema*), and taxes (VAT and other consumption taxes). The regulator has set up several tools in order to help the consumer understand his bill, most notably a dedicated webpage "Your Bill Explained" (*la bolletta spiegata*) and a consumer help-desk (*lo Sportello per il Consumatore*).
Latvia (MI)	According to Art. 31 3° of Electricity Market Law, the Public Utilities Commission (PUC) shall determine what kind of information and to what extent electricity supplier shall include in their bills and informative materials that are issued to the consumer. The regulations of the PUC determines that a bill shall include at least the electricity amount in kWh supplied in billing period, the amount charged for consumed electricity in euros and the average electricity price in euro per kWh during the billing period and fees for electricity distribution system services, other additional services and the mandatory procurements components and total fees for the billing period for consumers and other end-users to whom shall be issued invoices regarding electricity service supply.
Lithuania (BF)	Law on Energy of the Republic of Lithuania No. IX-884 and Law on Electricity of the Republic of Lithuania No VIII-1881. Article 31 regulate the communication of charges and consumption information to electricity consumers in Lithuania, as well as contractual conditions and changes to contracts. The consumer is entitled to receive information on

	conditions of service and electricity prices and tariffs, reports on prices, contract terms, conclusion and termination conditions.
Luxembourg (BF)	Article 2(5) of the Law of 1 August 2007 regulates the communication of charges and consumption information to electricity consumers in Luxembourg, as well as contractual terms. With respect to billing, the law states that electricity providers must transmit to residential customers transparent information on tariffs and prices.
Malta (MI)	Electricity Market Regulations (S.L. 545.16), Art. 8(3) regulates billing. Bills issued by Enemalta Corporation, Malta's electricity supplier, must include contact details of its subcontractor, ARMS Ltd, which is the company responsible for meter reading, billing, debt collections and customer care services. Households should receive bills calculated on actual consumption at least every six months. For households with a smart meter, these bills based on actual readings are more frequent. All bills show a breakdown of the price calculation, the total electricity consumption for that period as well as the average daily energy consumption, relevant tariffs and CO_2 emissions.
Netherlands (MI)	The Electricity Act, article 95, details the mandatory information to be provided on an energy bill and some associations provide recommendations for data presentation. The breakdown of an energy bill concerns supply costs ("*leveringskosten*"), network costs and metering costs, and then taxes ("*Belasting*"). While using green energy, some taxes are refunded ("*Belastingvermindering*").
Poland (MI)	The Energy Law, Art. 5. 6a - 6c. regulates the communication of charges and consumption information to electricity consumers in Poland. Electricity suppliers are to inform consumers about the fuel supply mix used in the previous calendar year and about a place where information is available about the impact of the production of energy on the environment (at a minimum in terms of carbon dioxide emissions and radioactive waste created). Electricity suppliers must also inform consumers about the amount consumed in the previous year and the place where information is available about the average electricity consumption for each connection group of recipients, energy efficiency improvement measures and the technical characteristics of energy-efficient appliances.
Portugal (BF)	Art. 54 d) and Art.55 c) and d) of Decree Law of 15 February 2006 regulate the communication of charges and consumption information to electricity consumers in Portugal. Under the law, consumers are entitled full and adequate information to enable their participation in the electricity market, access information in a transparent and non-discriminatory manner on applicable prices and tariffs, as well as complete and adequate information in order to promote energy efficiency and the rational use of resources.
Romania (HP)	Law 123/2012 (modified in 2014) ART.62 (1) h[9]) and art. 145 (4) p) and Law 123/2012 (modified in 2014) ART. 66 (1),(2) regulate the content of bills. The Energy Authority ANRE has made available to the consumer an explanatory sample of the components that have to be included in the bill. This model has been adopted by electricity suppliers, who can also opt to display the same document at their websites, in order to inform consumers about the contents of their bill.
Slovakia (MI)	The supplier of electricity and gas is, according to the § 17 article 14 of the Law 251/2012, obliged to inform the customer on the invoice or attached material about the particular components of the energy supply including the unit price. Information about the composition of the price component has to include the unit price especially for electricity purchase including the commercial activity of the supplier, distribution, losses during distribution, system services, system operation and taxes.
Slovenia (MI)	Beside standard items that must be included in every invoice issued in Slovenia that are stipulated by the Value Added Tax Act (invoice date, number, invoice issuer's contact details, amounts billed, VAT rate,…), consumers also have to receive certain information in their electricity bills, stipulated within Article 42 of the Energy Act, including the proportion of energy source that supplier used in preceding year in a way comparison between different suppliers can be made, the reference source where publicly available data on environmental impacts, expressed in CO_2 emissions and amounts of radioactive waste resulting from the electricity production in the preceding year, and consumers' rights related to dispute resolution.
Spain (HP)	Law 24/2013 establishes the type of information that should be included in an electricity bill. This format is mandatory for the suppliers of last resort. The details of the information are formally listed in the resolution N.5655 of 23 May 2014 of the Ministry for the Industry, Energy and Tourism. The resolution illustrates in its annex a template to be followed when producing electricity bills, showing in explanatory graphs and in detailed tables the mandatory information and its granularity.

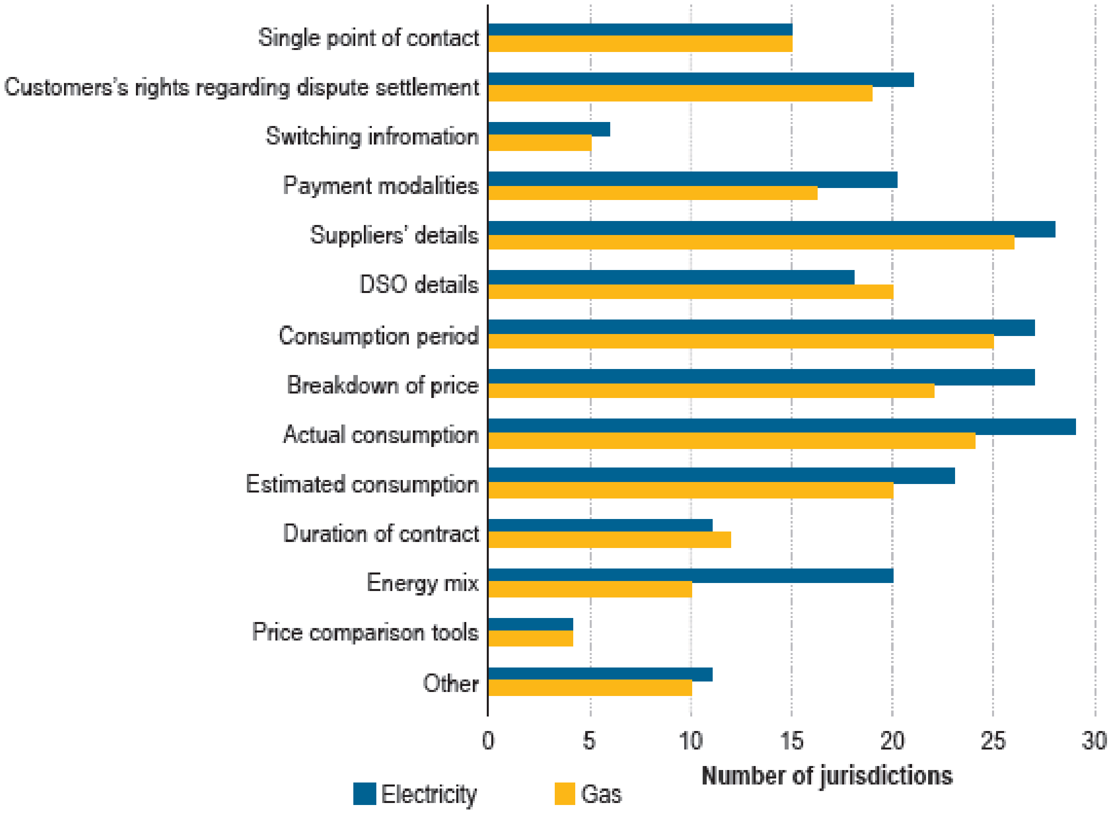
Sweden (BF)	The Electricity Act chapter 8, §14-16 specifies that an electricity supplier's billing shall be clear. It shall contain information on the measured consumption and current electricity prices that the billing shall be based on. The Swedish Energy Markets Inspectorate specifies in detail what shall be contained in electricity bills. The electricity cost consists of two parts: (1) a payment to the grid operator to stay connected and (2) payment for the actual electricity consumption and the electricity cost.
UK (MI)	The consumers' right to accurate consumption information is captured in Condition 31A of the Standard Licence which makes it incumbent on suppliers to provide customers with electricity consumption information in each bill (or, within the space of 30 days from a notice of increase in charges in cases where the latter is issued). In addition, suppliers must send an annual statement to all customers in a pre-defined format. Schedule 2ZB to the Electricity Act stipulates that licence-exempt suppliers must also provide consumption data to customers on an annual basis. Under Condition 12 of the Standard Licence, suppliers must take meter readings at least once every two years. Condition 21B of the Standard Licence allows customers to read their own meters as often as they choose. Suppliers are to reflect that reading in the subsequent bill. The structure of the bill is not fixed by any legislation.

In addition to EU and national legislative requirements, suppliers communicate and present information in different ways as a part of their non-price competition with other suppliers. For example, information may be presented in a certain format for branding purposes, or to target different customers with different kinds and levels of information to increase consumer satisfaction.

As a result of these three different factors – EU legislation, national legislation and commercial competition – there is therefore currently a broad divergence in Member States with regards to the individual elements in electricity and gas consumer bills and the total amount of information in these bills.

Figure 1 below from ACER summarizes the information provided to household customers on their bills. It includes general billing requirements put forward in Article 3 and Annex I of the Electricity and Gas Directives (for example, information on the single point of contact), as well as items not covered by EU law (price comparison tools). Whereas customers in the majority of Member States are currently provided with information on the consumption period, actual and/or estimated consumption, and a breakdown of the price, there is a greater diversity of national practices with regards to other potentially beneficial information, such as switching information, information about price comparison tools, and the duration of the contract.

Figure 1: Information on household customer bills in Member States – 2014



Source: CEER Database, National Indicators (2014-2015)

The results of a mystery shopping exercise on the information in energy bills covering ten representative Member States[263] provide a more detailed impression of the differences in billing practices within the EU. Mystery shoppers were instructed to analyse one of their own monthly, bi-monthly or quarterly electricity bills for a number of information elements identified as best practices by the Citizens' Energy Forum's Working Group on Billing[264] (Table 2) as well as a number of information elements addressed (although not always required) by the current Electricity Directive (Table 3)[265]. The exercise was carried out between 11 December 2014 and 18 March 2015.

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263 The Czech Republic, France, Germany, Italy, Lithuania, Poland, Slovenia, Spain, Sweden and the UK.

264 "*Implementation of EC Good Practice Guidance for Billing*", (2010) CEER, http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab1/E10-CEM-36-03_EC%20billing%20guidance_8-Sept-2010.pdf.

265 https://ec.europa.eu/energy/sites/ener/files/documents/20131219-e-billing_energy_data.pdf

Table 2: Information included on an electricity bill in a sample of ten Member States - I[266]

			Country									
Item	*Item in "billing" evaluation sheet*	% who found item on their bill (total)	CZ	DE	ES	FR	IT	LT[267]	PL	SE	SI	UK
Supplier's name	Provider's name	99%	96%	100%	100%	100%	100%	88%	100%	100%	100%	100%
Contact details (including their helpline and emergency number)	Telephone number of customer service/helpline	96%	92%	100%	100%	100%	100%	80%	93%	100%	100%	97%
	Postal address of provider	94%	92%	100%	97%	100%	100%	60%	100%	96%	100%	83%
	Email address of provider	69%	92%	95%	80%	27%	37%	40%	75%	84%	96%	60%
	Emergency number (e.g. to call in the event of an electrical emergency or power outage)	59%	68%	8%	97%	87%	93%	28%	35%	64%	40%	87%
The duration of the contract	Duration of the contract (e.g. 24 months)	22%	8%	50%	27%	17%	10%	0%	5%	40%	4%	50%
The deadline for informing the supplier about switching to another supplier	The period of notice to terminate your electricity contract (e.g. 30 days before the intended termination date)	19%	4%	50%	0%	57%	0%	12%	0%	28%	0%	27%
The tariff name	Tariff name/plan (e.g. '*Day & Night Fix*')	80%	84%	65%	57%	87%	93%	60%	93%	80%	76%	100%
(A reference to) a clear price breakdown for the tariff (the base price plus all other charges and	A detailed price breakdown for your tariff (e.g. division of total	79%	92%	65%	100%	83%	93%	8%	88%	92%	96%	73%

266 *"Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU"* (2016) European Commission.

267 Lithuania stands out as the country where mystery shoppers were the least likely to find each of the items on their bill. Mystery shoppers in Lithuania (note: all shoppers were clients of Lesto) reported that they do not receive an electricity bill; they declare usage themselves online (via www.manoelektra.lt - a site dedicated to Lesto customers) or by means of a paper bill book.

			Country									
Item	*Item in "billing" evaluation sheet*	% who found item on their bill (total)	CZ	DE	ES	FR	IT	LT[267]	PL	SE	SI	UK
taxes)	price in base price, network charge, etc.)											
The base price of one energy unit (in kilowatt hours or kWh) for the selected tariff	Base price per kWh of your tariff	82%	68%	65%	87%	93%	83%	68%	83%	92%	88%	93%
The switching code	Switching code/meter identification (EAN or MPAN code; a unique code for your electricity meter)	73%	96%	58%	87%	87%	67%	44%	78%	76%	72%	67%
The amount to be paid, for which billing period, by when and how	Amount to be paid	97%	100%	100%	97%	97%	100%	72%	100%	100%	100%	97%
	Billing period (e.g. 15 November – 14 December 2014)	95%	96%	90%	100%	97%	100%	80%	93%	100%	100%	97%
	Payment method (e.g. direct deposit, cheque, bank transfer)	84%	88%	100%	87%	87%	87%	64%	65%	92%	64%	100%
Clear information on how this amount has been calculated: is it based on an actual meter reading or estimated only?	% of shoppers stating that it not clear how the billing amount was calculated	5%	4%	18%	3%	0%	0%	8%	3%	4%	4%	3%
For calculations based on actual consumption: meter readings and consumption during the billing period (measured in kilowatt hours or kWh)	Details about consumption during billing period (in kWh)	89%	95%	67%	96%	100%	100%	73%	95%	87%	91%	95%
	Value of the meter reading at the end of the billing period	89%	90%	93%	96%	86%	88%	73%	95%	87%	82%	95%
	Value of the meter reading at the beginning of the billing period	88%	95%	93%	96%	86%	88%	73%	86%	83%	91%	90%
Where does the energy come from, how is it generated, how environment friendly is it ("the fuel mix")	Fuel mix/energy sources (e.g. wind power, biomass)	32%	48%	45%	20%	47%	43%	0%	18%	52%	40%	13%
Information on how to get tips on saving energy (e.g. a link to a website)	Tips on saving energy (e.g. link to a website)	26%	8%	48%	17%	23%	20%	36%	8%	24%	20%	57%
Information on how to obtain the bill in alternative formats (e.g. in large print) for	Information on how to obtain your bill in alternative format	24%	16%	8%	23%	27%	53%	28%	5%	20%	16%	50%

			Country									
Item	*Item in "billing" evaluation sheet*	% who found item on their bill (total)	CZ	DE	ES	FR	IT	LT[267]	PL	SE	SI	UK
consumers with disabilities	(e.g. paper/online, large print)											
Base *(note: figures in grey are based on a smaller sample):*		300	25	40	30	30	30	25	40	25	25	30

Table 3: Information included on an electricity bill in a sample of ten Member States - II[268]

			Country									
Item	*Item in "billing" evaluation sheet*	% who found item on their bill (total)	CZ	DE	ES	FR	IT	LT	PL	SE	SI	UK
The contribution of each energy source to the overall fuel mix of the supplier over the preceding year	13a. Fuel mix/energy sources (e.g. wind power, biomass)	32%	48%	45%	20%	47%	43%	0%	18%	52%	40%	13%
Information concerning the consumer's rights as regards the means of dispute settlement available to them in the event of a dispute	8b. National contact information point (or single point of contact where you can obtain information about your energy rights)	28%	44%	43%	33%	43%	30%	4%	3%	16%	12%	53%
	8c. An energy mediator or third-party assistance	23%	36%	45%	23%	57%	0%	0%	3%	12%	0%	50%
Base:		300	25	40	30	30	30	25	40	25	25	30

268 Shoppers were instructed to analyse a monthly or quarterly bill. In the Czech Republic and Germany, a considerable number of shoppers reported that they only receive an annual bill from their electricity company. In these countries, 88% (n=22) and 50% (n=20), respectively, of shoppers analysed an annual bill. "*Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU*" (2016) European Commission.

The results show a large variation across countries for selected items; for example, information about the period of notice to terminate a contract was not found on bills in Italy, Poland, Slovenia and Spain, while in Germany and France, at least half of shoppers had found such information on their bill (50% and 57%, respectively). These variations may reflect national differences in consumer preferences and the characteristics of local markets, as reflected in Member State rules and discretionary billing practices by suppliers. In addition, Table 3 illustrates the possible bad application of certain EU requirements. Only 28% of mystery shoppers (including experts) were able to find a contact point where they could obtain information about their energy rights, as required under Article 3(9)(c) of the Electricity and Gas Directives[269]. In addition, Article 3(9)(a) of the Electricity Directive requires suppliers to specify the contribution of each energy source to the overall fuel mix of the supplier over the preceding year in or with consumer bills[270]. However, more than a third (35%) of mystery shoppers in the same study disagreed that their electricity company informed them about how the electricity they used was produced (scores 0 to 4 on a scale to 10)[271].

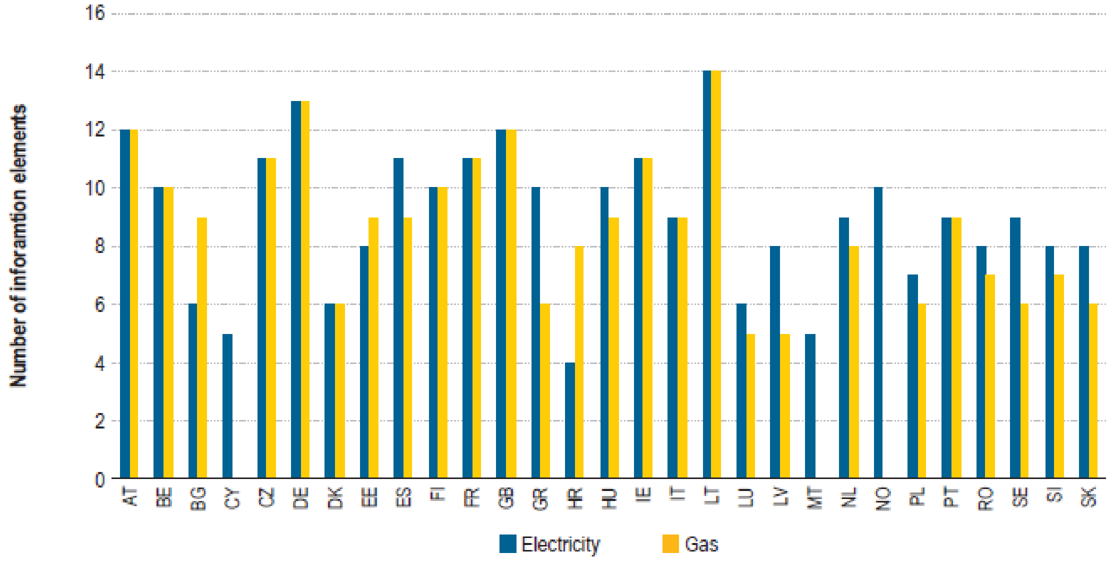
As transposition checks for the directives do not indicate particular irregularities around these articles. This points to possible interpretation issues or the bad application of the relevant measures by national authorities.

269' *'Member States shall ensure that electricity suppliers specify in or with the bills and in promotional materials made available to final customers… the contribution of each energy source to the overall fuel mix of the supplier over the preceding year in a comprehensible and, at a national level, clearly comparable manner…'*

270 *'Member States shall ensure that electricity suppliers specify in or with the bills and in promotional materials made available to final customers… information concerning their rights as regards the means of dispute settlement available to them in the event of a dispute.'*

271 This was the case for a majority of respondents in nine EU-28 countries, with the highest level of disagreement observed in Bulgaria (78%). On the other end of the scale, the proportion of respondents who "strongly agreed" (scores 8 to 10) that their electricity company informed them about how the electricity they used was produced varied between 5% in Bulgaria and 46% in Austria. Germany joined Austria at the higher end of the country ranking with 45% of respondents who "strongly agreed".

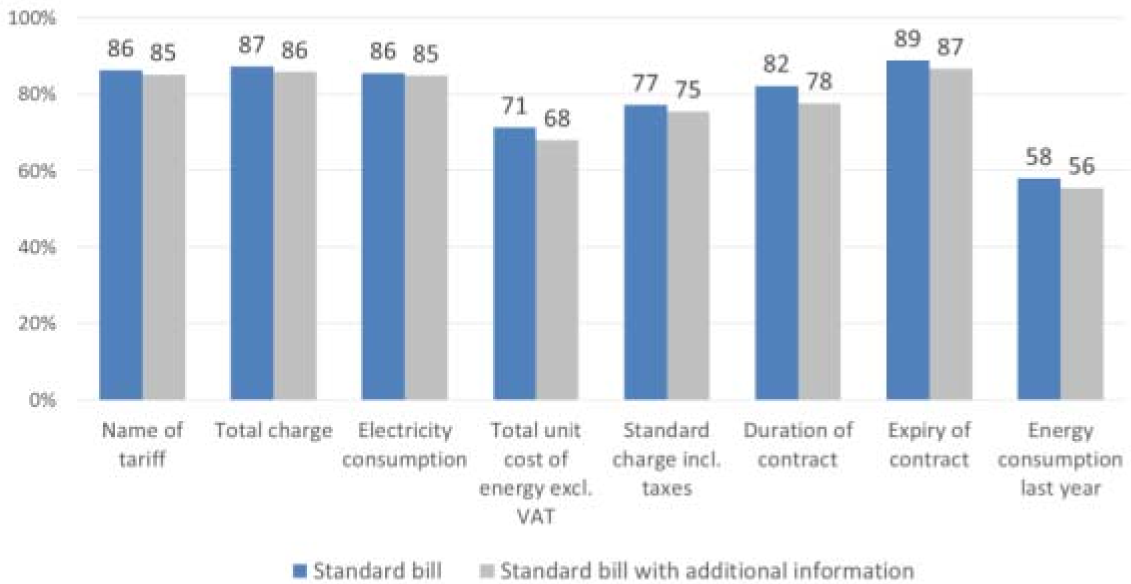
Figure 2: Information on household customer bills in Member States – 2014 (number of information elements)



Source: CEER Database, National Indicators (2014-2015)

To illustrate another dimension of divergence, Figure 2 above shows information load in consumer bills in different Member States. This can have a significant impact on consumers' ability to comprehend their bills – another issue flagged up by stakeholders and confirmed by a Commission behavioural experiment that showed that superfluous information in energy bills made it difficult for consumers to understand them (Figure 3).

Figure 3: Performance in bill comprehension task: standard bill vs standard bill with additional information



Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission

To summarize, there is currently a broad divergence in Member States, both with regards to the individual elements in consumer bills and the total amount of information in these bills. The widespread divergence in national practices reflects differences in national legislation and marketing by suppliers, which are themselves a function of consumer preferences and the characteristics of local markets. To a more limited extent, the divergence may also reflect the bad application of certain requirements of the Electricity and Gas Directives, particularly EU requirements on information on consumer rights and energy sources.

7.6.3. *Deficiencies of the current legislation*

As addressed in more detail in Section 7.1.1 and Annex V of the Evaluation, the Electricity and Gas Directives grant consumers the right to comparable and transparent supply options. They also state that consumers must be properly informed of their actual energy consumption and costs frequently enough to regulate their consumption. Building on these general provisions, the Energy Efficiency Directive puts in place requirements on the frequency of bills and the presentation of cost and consumption information in bills.

One of the major objectives of the Articles in the Electricity and Gas Directives relevant to billing was enabling easier and more effective consumer choice[272]. There exist various data that help us understand how EU consumers perceive their energy bills and the extent to which their bills are building awareness about energy use. These data are summarised in the remainder of this Section.

Consumer organisations responding to the latest ACER Market Monitoring Report stated that the average electricity and gas consumer in their countries is only able to compare prices to a limited extent. The average score was 4.8 and 5.0 on a scale from 1 to 10 for electricity and gas respectively[273].

These mediocre figures are backed by the 2016 Electricity Study that found that one in five consumers surveyed still disagree that the electricity bills of their electricity company were easy and clear to understand (Figure 4) – note the disparity in individual Member States concerning the level of understanding with Bulgaria performing worst and Cyprus performing best). This effect was even more pronounced among mystery shoppers from ten Member States who were quizzed with their current bills to hand. Here, between 20 and 54% of respondents disagreed with the statement “My bill is easy to understand” (Figure 5)[274].

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[272] Boost competition on retail markets and create consumer incentives to save energy were other major objectives. See the Thematic Evaluation on Metering and billing.

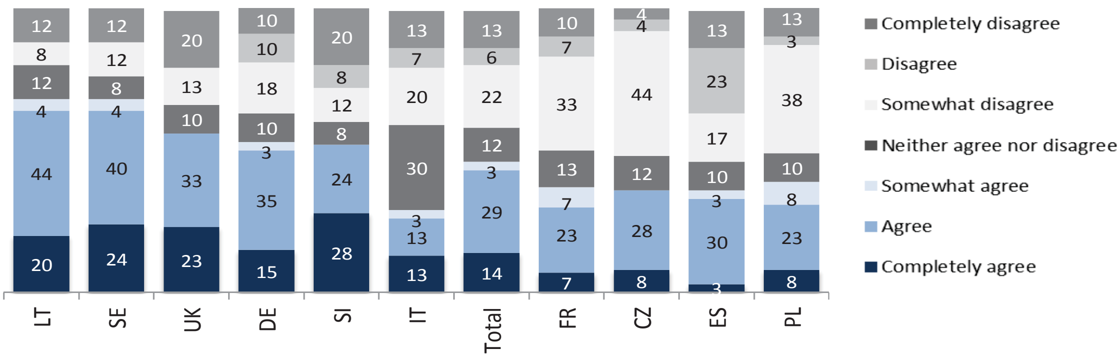
[273] "*Market Monitoring report 2014*" (2015) ACER, http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015.

[274] "*Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU*" (2016) European Commission.

Figure 4: Agreement with statement: "bills of my electrify company are easy and clear to understand", by country[275]

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

Figure 5: Agreement with the statement: "My bill is easy to understand"[276]



Q14. To what extent do you agree with the following statement: "my bill is easy to understand"?
%, Base: all mystery shoppers

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

The complaints data collected through the European Consumer Complaints Registration System indicates the largest share (28%) of consumer complaints reported to the Commission between 2011 and 2016 were related to billing (Figure 6). Whilst the complaints classified as relating to "unjustified" or "incorrect" invoicing/billing (10% of all electricity and gas complaints) are most likely related to billing on estimated rather than actual consumption[277], complaints about unclear invoices or bills make up around 1% of all electricity and gas complaints in the system. The category 'other billing complaints' relates to cases where users of the European Consumer Complaints

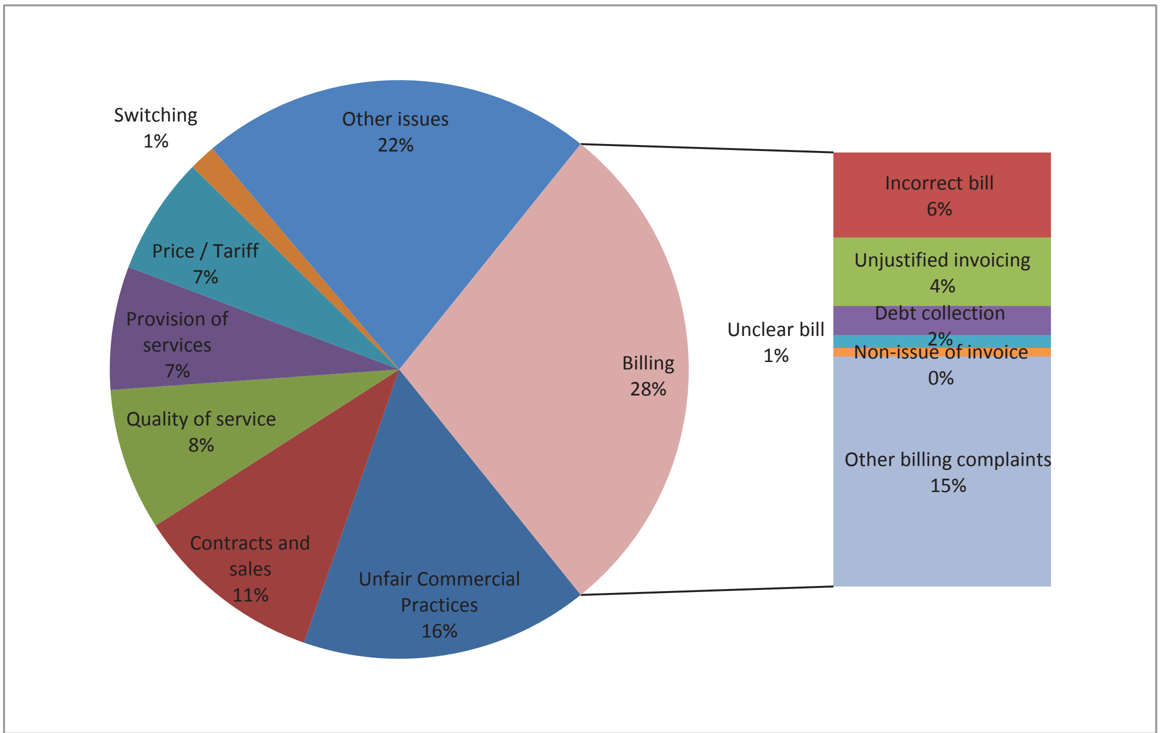
[275] Question: "The following question deals with the quality of services offered in the electricity retail market. Please indicate how much you agree or disagree with each of the following statements, using a scale from 0 to 10, where 0 means that you "totally disagree" and 10 means that you "totally agree": Bills of [PROVIDER] are clear and easy to understand."

[276] Agreement with the statement: "*My bill is easy to understand*."

[277] See Thematic Evaluation on Smart Metering.

Registration System did not encode a sub-category, or where their specific complaint could not be categorised according to the options presented below.

Figure 6: Electricity and gas consumer complaints, 2011-2016



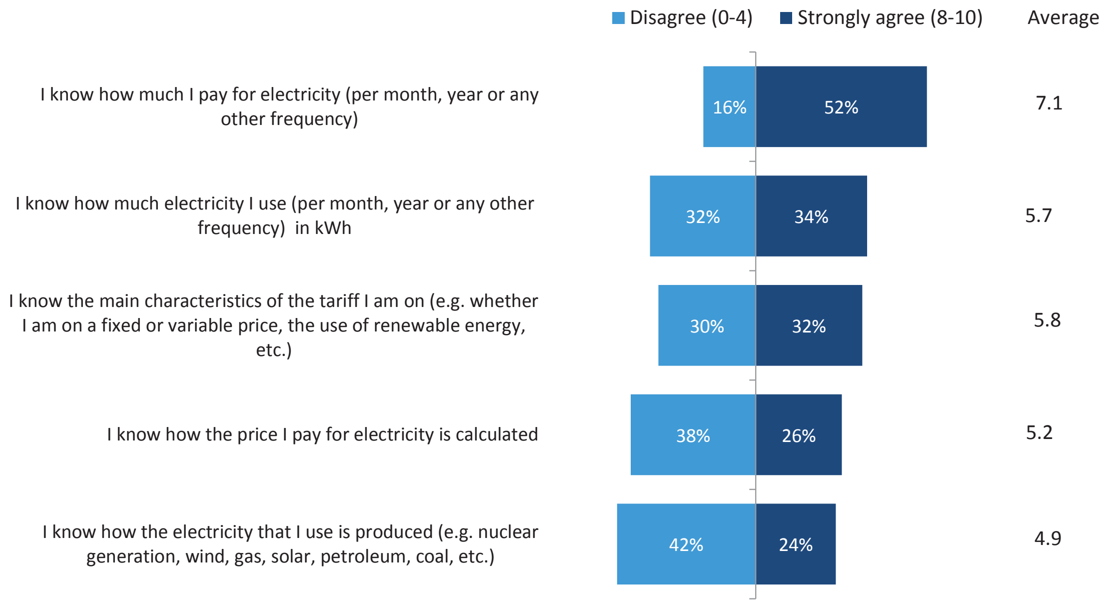
Source: DG JUST, European Consumer Complaints Registration System.

It therefore appears that whereas a significant percentage of EU consumers do indeed have difficulties understanding their energy bill, problems directly related to bill clarity have not led to a large number of consumer complaints compared with other issues such as back-billing, unfair commercial practices, and contractual clauses. However, looking at consumer complaints alone may be insufficient as complaint levels are influenced by consumer awareness and expectations, both of which may be low when it comes to energy bills.

Energy bills are the foremost means through which suppliers communicate with their customers. As such, consumers' ability to correctly answer simple questions about their own electricity use indirectly reveals the extent to which bills have been effective in providing information that could facilitate effective consumer choice. Figure 7 below shows that whereas the majority of EU consumers report that they know how much they pay for electricity, fewer were aware of their consumption in terms of kWh, what type of tariff they have, or their sources of electricity.

Whilst this finding may certainly reflect a lack of consumer interest in this information, the information facilitates effective consumer choice by helping consumers identify the best offer in the market and weigh the benefits of switching. Their omission from many bills, as the data presented in Table 2 and Table 3 above illustrates, may therefore be impeding the achievement of one of the stated objectives of the billing provisions in the Electricity and Gas Directives.

Figure 7: Self-reported awareness of electricity use[278]



Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

To summarize, the analysis presented in this Section indicates that there is scope to improve the extent to which the billing provisions in the Electricity and Gas Directives facilitate consumer choice. To help consumers accurately assess information, the legislation can provide some degree of standardisation to allow consumers to make accurate comparisons between offers, which is difficult to achieve through the market alone. Standardisation of some information can also be useful to build familiarity and help consumers recognise or retain important information.

As Figure 8 below illustrates, the difference in price between offers in the market can be significant, and so even marginal gains in consumers' ability to identify the best deal can result in a significant impact on consumer savings.

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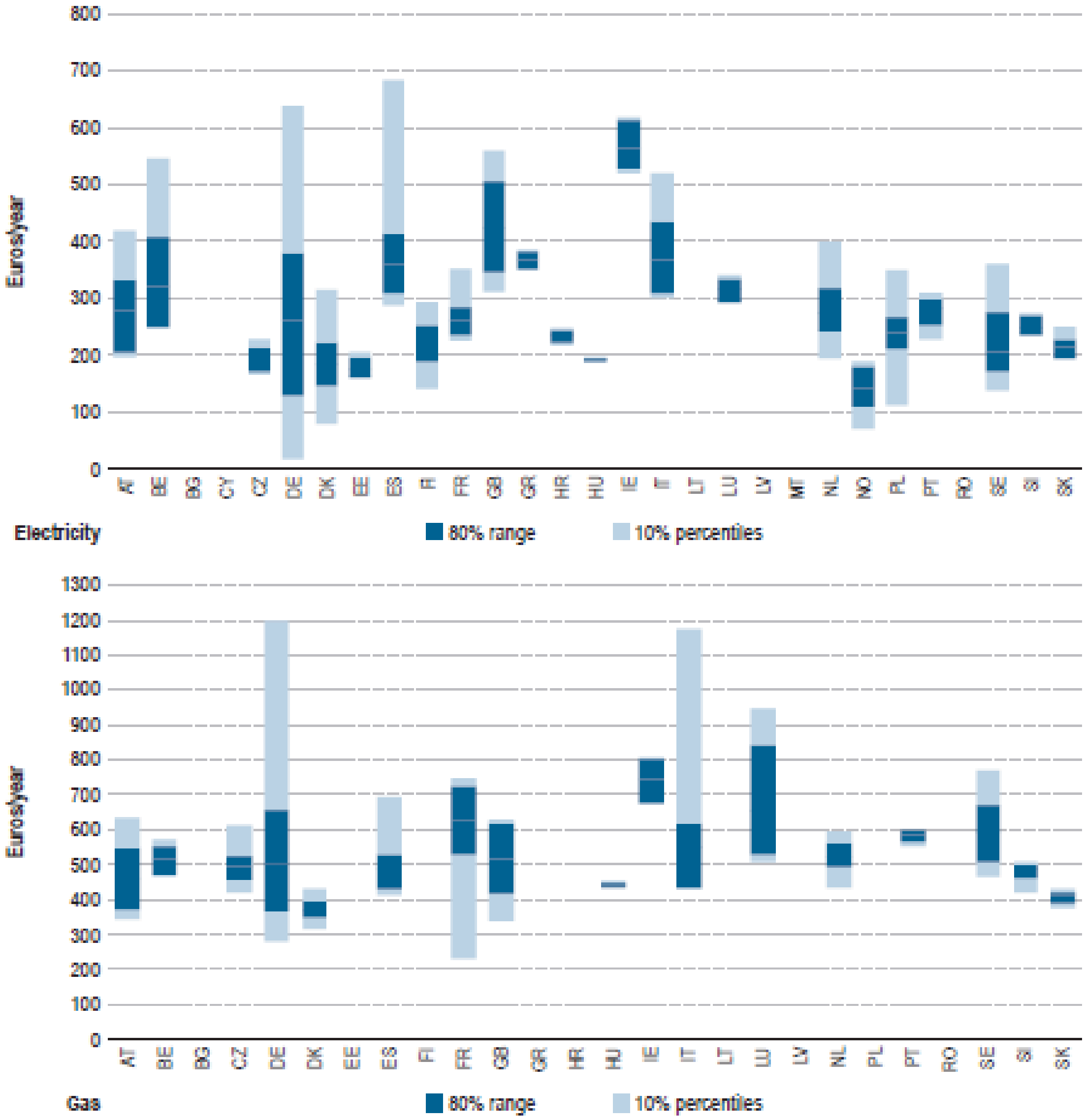
[278] Question: "Please indicate how much you agree or disagree with each of the following statements, using a scale from 0 to 10, where 0 means that you “totally disagree” and 10 means that you “totally agree”."

Figure 8: Dispersion in the energy component of retail prices for households in capitals – December 2014



Source: ACER Retail Database (November–December 2014) and ACER calculations.

7.6.4. <u>*Presentation of the options*</u>

Option 0: BAU with stronger enforcement

Whilst no additional legislation is proposed, the Commission actively follows up evidence suggesting possible cases of the bad application of EU law by Member States uncovered in the evaluation. Specifically, the following elements of the current legislation may not be being adhered to in certain Member States:

- Article 3(9)(a) of the Electricity Directive, which requires suppliers to specify the contribution of each energy source to the overall fuel mix of the supplier over the preceding year in or with consumer bills;
- Article 3(9)(c) of the Electricity and Gas Directives, which requires suppliers to include information on consumer rights in or with bills.

Option 0+: Non-regulatory approach; Commission Recommendation on billing information

This includes general principles such as:

- Making information which is essential for understanding the price which consumers pay for the service prominent, clear and easy to read on the bill. One way to achieve this is to present it in a standard "comparability box" that should feature prominently on the bill and include all the key information that consumers need to compare offers and switch suppliers.
- Ensuring that there is a link to a national authority competent to lead a billing review process and information campaigns.

Option 1: More detailed legal requirements on the key information

Specifically, this includes:

- Requiring electricity and gas suppliers to 'prominently display' in every household energy bill, both paper and electronic, eight key pieces of information[279] initially identified by the Citizens' Energy Forum Working Group on Billing in 2009[280]. Not all of these data are covered by the existing legislation, and their inclusion would help ensure that consumers have the minimum information necessary to interact with the market, whilst leaving Member States freedom to tailor the presentation of this information to national markets.
- Requiring the breakdown of energy costs presented to consumers to be in line with the new Regulation on electricity and natural gas price statistics i.e. three components (energy costs, network charges, taxes & levies) with standard definitions throughout the EU. This could help improve consumer awareness on the factors affecting price changes and enable the cross-border comparison of bills.

Option 2: A fully standardized 'comparability box' in bills

This option would be to develop a standard EU information box that would prescriptively present all the key information that consumers need to compare offers and switch suppliers prominently on the bill. It may also most require implementing legislation to define the format and contents of the information box.

7.6.5. *Comparison of the options*

This Section compares the costs and benefits of each of the Options presented above in a semi-quantitative manner.

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[279] i) The price to pay; ii) Consumption for current billing period, including comparison with previous year (as per EED); iii) The name of the energy supplier; iv) The contact details of the energy supplier; v) The tariff name; vi) Contract duration; vii) The customer's switching code or unique identification code for their supply point; viii) A contact point for alternative dispute resolution (as per current Electricity and Gas Directives).

[280] "*Implementation of EC Good Practice Guidance for Billing*", (2010) CEER http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab1/E10-CEM-36-03_EC%20billing%20guidance_8-Sept-2010.pdf.

In general, the costs of implementing each of the above measures can be estimated to a reasonably certain degree using tools such as the standard cost model for estimating administrative costs[281]. However, no data or methodology exists to accurately quantify all the benefits of the measures in terms of direct benefits to consumer (consumer surplus) or general competition. As such, this Section draws on behavioural experiments from a controlled environment to evaluate the impact of some policy options on consumer decision-making. Where appropriate, it aims to illustrate the possible direct benefit to consumers assuming certain conditions. It also highlights important qualitative evidence from stakeholders that policymakers should also incorporate into their analysis of costs and benefits.

Option 0: BAU with stronger enforcement

A good case can be made for a prudent, business-as-usual approach in this policy area. First, there appear to be implementation issues on certain bill items required under current EU legislation.

Secondly, even though there are clear issues around billing, a recent Commission survey showed that 77% of energy consumers either agreed or strongly agreed that their bills were "easy and clear to understand" (Figure 5), and unclear bills led to just 1% of the electricity and gas consumer complaints reported to the Commission (Figure 6). Even after factoring in the unreliability of some consumer report data, the absolute size of the problem itself does not therefore appear to be very significant.

And thirdly, national regulators and energy suppliers are implementing various ways of improving the billing experience. A business as usual approach would allow 'natural experiments' in this area to be developed, and the Commission to gather stronger evidence for a more targeted intervention at a later date.

In spite of these considerations, **it is unlikely that Option 0 would most effectively address the problem of poor consumer engagement**. Whilst adherence to certain billing requirements does seem to be lacking, this only relates to one or possibly two information items, and so even ensuring 100% compliance would therefore not result in significant change to energy bills. Whilst consumers report satisfaction with bill clarity, questionnaires reveal glaring shortcomings in their knowledge of basic market-relevant information that would help them identify the best offer in the market and weigh the benefits of switching – information that could be more effectively conveyed in bills.

Accordingly, consumer groups strongly support further legislative measures to ensure bills inform consumer better and help them to engage with the market. Indeed, all major stakeholder groups – except for energy suppliers and industry associations – indicate that there may be at least some scope for further EU action to ensure bills facilitate consumer engagement in the market.

There are **no implementation costs** associated with Option 0.

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[281] http://ec.europa.eu/smart-regulation/guidelines/tool_53_en.htm

Option 0+: Non-regulatory approach e.g. a Commission Recommendation on billing information

This option can be discarded because a very similar set of recommendations have already been developed by the Commission-chaired Working Group on Billing (more details below). Whilst the group's findings were published and presented to the Citizens' Energy Forum in 2009, these recommendations have not been fully adhered to (Table 2), and it is unlikely that putting them in a non-binding Commission Recommendation would change this. It is thus unlikely that voluntary cooperation between Member States would address this problem.

Option 1: More detailed legal requirements on the key information

To recap, this option would involve ensuring that all EU suppliers use the same definitions of price components (energy, network charges, and taxes) when communicating with consumers. It would also involve prominently displaying the eight pieces of information presented in every EU energy bill. These eight items are drawn from a guidance document on billing originally proposed by a Commission-led Working Group in 2009[282]. The importance of the information items was then reaffirmed by a Working Group on e-Billing and Personal Data Management in 2013[283]. Whilst the former comprised of representatives from NRAs and the Commission, the latter also included representatives from consumer groups and industry. The identification and selection of these items is therefore based on comprehensive of stakeholder dialogue process.

The **economic benefits** of Option 1 will primarily be indirect, and come in terms of greater competition (lower prices, higher standards of service and a broader variety of products on the market). These benefits are unquantifiable.

In addition, Option 1 will directly result in **greater consumer surplus**, something that can be estimated using the following assumptions.

As a whole, EU households spend a total of 147 billion euros on electricity and 97 billion euros on gas annually, the average annual household bill being 773 euros for electricity and 795 euros for gas[284]. According to CEER, 6.3% of electricity consumers and 5.5% of gas consumers switched energy suppliers in 2014.

If we assume that:

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[282] "*Implementation of EC Good Practice Guidance for Billing*" (2010) CEER http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab1/E10-CEM-36-03_EC%20billing%20guidance_8-Sept-2010.pdf.

[283] "*Working Group Report on e-Billing and Personal Data Management*", (2013) Report prepared for the 6th Citizens' Energy Forum, https://ec.europa.eu/energy/sites/ener/files/documents/20131219-e-billing_energy_data.pdf.

[284] Not including MT or CY. Based on latest data available: 2014 for BE, BG, CZ, DK, EL, HR, HU, IT, LV, PL, RO, and SK; 2013 for DE, ES, LU, NL, UK; 2012 for EE, FI, LT, SE and SI; 2011 for FR; 2010 for AT, IE and PT. Source: Eurostat.

- The average EU switching rates for electricity and gas remained unchanged at 6.3% and 5.5% respectively[285];
- The measures improved the ability of one out of every one-hundred customers who switched to identify a better offer[286];
- The measures benefitted consumers using comparison tools just as much as those comparing the market directly through suppliers[287];
- These consumers were able to save an additional 5 euros from both their electricity and gas bills a year as a result of the measures put in place[288];
- The financial advantage of being able to identify the best deal as a result of these measures persists for four years[289];
- All EU households are able to benefit from these changes equally in relative terms[290];
- A discount rate of 4% for the consumer benefits year on year;

then Option 1 would result in an increase in consumer surplus **of between 0.9 and 3.2 million euros annually** (depending on the year of implementation), and **27.6 million euros in total for the period 2020-2030**.

[285] This is a conservative assumption given that 40% more consumers would have access to their unique switching code with every bill (a piece of information important for switching) and significantly more consumers on fixed term contracts are likely to be aware of when their current contracts expired (24% of household consumers report that they only compare tariffs when they needed to renew their contracts). "*Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU*" (2016) European Commission.

[286] This equates to just 0.063% of electricity consumers and 0.055% of gas consumers in any given year – again, a conservative assumption. Taken as a whole, the eight information items in Option 1 aim to arm the consumer with all the most relevant information necessary to engage with the market, including helping consumers identify the best offer.

[287] One of the benefits of this intervention would also be to give consumers easy access to all information relevant to using comparison tools in every bill (switching code, tariff name, consumption).

[288] This figure seems proportionate given that the average 80% range of the dispersion of electricity and gas household offers in the market is around EUR 150 (Figure 8). Assuming that those switching would tend to be moving from a tariff at the more expensive side of this distribution to a tariff at the cheaper side of this distribution, this amounts to saying that the greater market awareness engendered by this intervention would enable consumers to identify an offer that was just c. 3% cheaper than the offer they would have otherwise identified without the intervention.

[289] A conservative assumption given the implied average time between switches is upwards of 15.5 years for electricity consumers and 18 years for gas consumers.

[290] In reality, households will react differently depending on consumers' needs, skills, motivations, interests, lifestyle, and access to resources such as accurate online comparison tools. However, we have no reliable data to quantify these differences in this specific context.

Table 4: The prevalence of eight key information items in consumer bills

Item	*Item in "billing" evaluation sheet*	*% who found item on their bill (total)*
i) The amount to be paid, for which billing period, by when and how (existing EU legal requirement)	Amount to be paid	97%
	Billing period (e.g. 15 November – 14 December 2014)	95%
ii) For calculations based on actual consumption: meter readings and consumption during the billing period (measured in kilowatt hours or kWh) (existing EU legal requirement)	Details about consumption during billing period (in kWh)	89%
	Value of the meter reading at the end of the billing period	89%
	Value of the meter reading at the beginning of the billing period	88%
iii) Supplier's name	Provider's name	99%
iv) Contact details (including their helpline and emergency number)	Telephone number of customer service/helpline	96%
	Postal address of provider	94%
	Email address of provider	69%
	Emergency number (e.g. to call in the event of an electrical emergency or power outage)	59%
v) The tariff name	Tariff name/plan (e.g. '*Day & Night Fix*')	80%
vi) The duration of the contract	Duration of the contract (e.g. 24 months)	22%
vii) The switching code	Switching code/meter identification (EAN or MPAN code; a unique code for your electricity meter)	73%
viii) Information concerning the consumer's rights as regards the means of dispute settlement available to them in the event of a dispute (existing EU legal requirement)	National contact information point (or single point of contact where you can obtain information about your energy rights)	28%
	An energy mediator or third-party assistance	23%
Base *(note: figures in grey are based on a smaller sample):*		300

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

The **implementation costs** of Option 1 will most likely be modest because:

- All Member States have legislation with billing requirements that are more prescriptive than those in the EU *acquis* (Table 1);
- National legislation is periodically revised independently of EU requirements, and so minor EU requirements would not lead to significant additional implementation costs to national administrations;
- It is already an EU legal requirement to display three out of the eight pieces of information this measure proposes should be 'prominently displayed' (information on consumption, information on costs, and information on dispute settlement);
- Only one piece of information (the contract duration) would have to be added to around 80% of EU bills;
- Two pieces of information (the tariff name and switching code) can already be found in over 70% of bills;
- The remaining two pieces of information (the suppliers name and contact details) can already be found in over 95% of bills (Table 4);

- The requirement to use standardised definitions of energy price component would not result in any additional information requirements, *per se*.

This option would therefore result in the following one-time implementation costs to the 2752 electricity and 1595 gas suppliers in the EU[291]. No running costs are associated with this option due to the computerisation of billing systems.

Table 5: Option 1 implementation costs (all one-time costs)[292]

Obligation	Action	Suppliers concerned	Staff type	Hourly rate (EUR)	Man hours	Activity cost (EUR)
Ensuring 8 key information items are prominently displayed in every energy bill	Bill design	2174[293]	Professionals	32.10	16	1,116,566.40
	Bill design	1449[294]	Professionals	32.10	72	3,348,928.80
Ensuring that all EU suppliers use the same definitions of price components in bills	Understanding information obligation	3434[295]	Professionals	32.10	4	440,925.60
	Adjusting existing data	3434	Professionals	32.10	24	2,645,553.60
					Total	**7,551,974.40**

As regards stakeholder views, Option 1 would likely enjoy broad support amongst stakeholders, apart from energy suppliers and the industry associations who represent them. It responds to the input from consumer groups, the European Parliament and the Committee of the Regions that legislative action is necessary to ensure that energy bills meet minimum standards. It also accommodates feedback from NRAs that prescriptive or detailed EU requirements could reduce the scope for innovation among suppliers and could become outdated quickly.

Option 2: A fully standardized 'comparability box' in bills

To recap, this option would be to develop a standard information box that would prescriptively present key information in all EU energy bills.

The **economic benefits** of Option 2 would primarily be indirect, and come in terms of greater competition (lower prices, higher standards of service and a broader variety of products on the market). These benefits are unquantifiable.

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291 Source: CEER National Indicators Database (2015).

292 Derived from the standard cost model for estimating administrative costs.

293 This assumes that 50% of all suppliers would need to make minor changes to their bills to accommodate one additional piece of information (contract duration). 2 man days of work. Estimate based on the figures in Table 4

294 This assumes that 30% of all suppliers would need to make moderate changes to their bills to accommodate three additional pieces of information (contract duration, switching code, tariff name). 9 man days of work. Estimate based on the figures in Table 4.

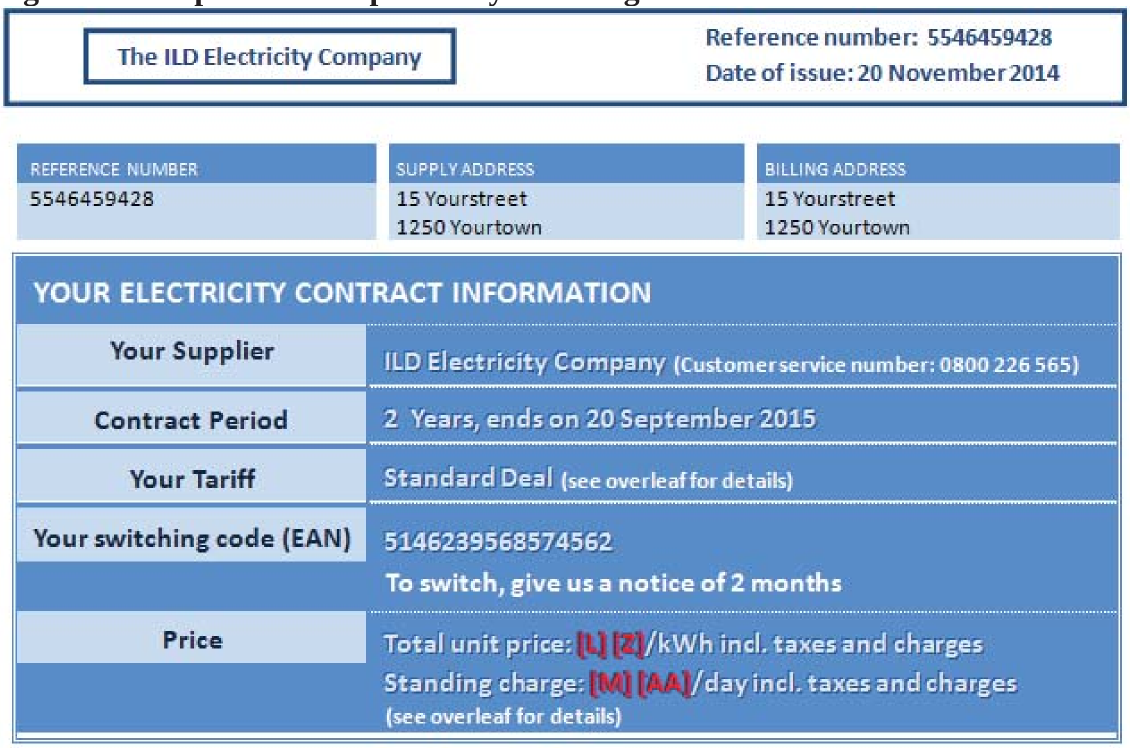
295 79% of consumers found a breakdown of energy costs in their bills (Table 2). This legal requirement would only apply to suppliers providing a breakdown.

In addition, Option 2 would directly result in **greater consumer surplus**, something that can be estimated with the aid of the following behavioural experiments.

10,056 respondents completed behavioural experiments to test if bill presentation impacts consumer awareness and decision making. The behavioural experiment included a task on bill comprehension, in which respondents were shown a best practice bill with a comparison box or a standard bill and tested on how well they understood key pieces of information contained in the bill. Respondents were also tested on their ability to identify the best offer after having seen a best practice bill or a standard bill.

The "best practice" bill drew on the Working Group Reports on Billing, and Personal Data Management cited earlier, as well as the electricity bill model/prototype developed following input received from working group members, which makes suggestions for both the content and format of an electricity bill and encourages the use of a "comparability box".

Figure 9: Best practice comparability box design



The ILD Electricity Company

Reference number: 5546459428

Date of issue: 20 November 2014

REFERENCE NUMBER	SUPPLY ADDRESS	BILLING ADDRESS
5546459428	15 Yourstreet 1250 Yourtown	15 Yourstreet 1250 Yourtown

YOUR ELECTRICITY CONTRACT INFORMATION	
Your Supplier	ILD Electricity Company (Customer service number: 0800 226 565)
Contract Period	2 Years, ends on 20 September 2015
Your Tariff	Standard Deal (see overleaf for details)
Your switching code (EAN)	5146239568574562 To switch, give us a notice of 2 months
Price	Total unit price: [L] [Z]/kWh incl. taxes and charges Standing charge: [M] [AA]/day incl. taxes and charges (see overleaf for details)

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

The "standard bill" was developed based on the bills collected through desk research on actual providers in Europe. It does not have a comparability box and, although it provides consumers with the same information, the presentation of the information is not as clear (i.e. key information on tariff characteristics are not presented in a simple box on the first page of the bill).

Figure 10: Excerpt of standard bill

YOUR TARIFF INFORMATION

TARIFF NAME	STANDARD FIX
Base unit price	[insert currency symbol/amount]/kWh
Standing Charge	[insert currency symbol/amount]/kWh
National levy(the Green Energy Fund)	[insert currency symbol/amount]/kWh
TOTAL UNIT COST WITHOUT VAT	[insert currency symbol/amount]/kWh
+ VAT at 20%	[insert currency symbol/amount]/kWh
TOTAL UNIT COST incl. VAT	[insert currency symbol/amount]/kWh

DATE	GENERAL METER NO 7546 - reading
Previous reading*	32250kWh (a)
15 August	33570kWh (a)
14 November	34100kWh (a)
Your consumption 15 August – 14 November 2014	530 kWh

**Abbreviations: "a": actual, "e": estimate*

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

In the comprehension exercise, respondents were asked eight questions about the information provided in the bill, each of which had a single correct answer (respondents could see the bill next to the questions they had to answer). Generally, viewing the bill in the best practice format helped respondents pick out the correct answer when compared to the standard bill. On average across all questions, 84% of respondents who saw the best practice bill selected the correct answers, compared to 79% of respondents who saw the standard bill. This result is statistically significant for all eight questions as illustrated in the table below.

Table 6: Shares of respondents who correctly answered the bill comprehension test questions, by basic bill type

Question	Best practice bill	Standard bill	Difference
What is the name of your tariff?	90%	86%	5 pp***
How much are you being charged in total?	90%	87%	3 pp***
How much electricity did you consume?	91%	87%	4 pp***
What is the total unit cost of energy excl. VAT?	77%	72%	6 pp***
What is the standing charge incl. taxes and charges?	82%	78%	4 pp**
What is the duration of your contract?	90%	80%	10 pp***
When does your contract expire?	90%	88%	2 pp*
How much energy did you consume last year?	60%	52%	8 pp***
Average across all questions	84%	79%	5 pp***

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

In the 'stay or switch' task, designed to test if the presentation format of consumers' bills impacts their propensity to switch to the cheapest tariff, best practice bills also led to better performance, albeit to a limited extent. Respondents viewing the “best practice” bill were more likely to choose the cheapest deal compared to those viewing the “standard” bill (61% compared to 59%), this impact is small and only marginally statistically significant overall (Table 7).

Table 7: Share of respondents who selected the cheapest deal[296]

Bill type	All countries	CZ	DE	ES	FR	UK	IT	LT	PL	SE	SI
Best practice	61%	59%	64%	53%	59%	72%	52%	60%	59%	63%	59%
Standard	59%	59%	61%	51%	55%	70%	55%	58%	53%	57%	58%

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

If we assume that:

- The average EU switching rates for electricity and gas remained unchanged at 6.3% and 5.5% respectively[297];
- The measures improved the ability of two out of every one-hundred customers who switched to identify a better offer, reflecting the results in Table 7[298];
- The measures benefitted consumers using comparison tools just as much as those comparing the market directly through suppliers[299];
- These consumers were able to save an additional 5 euros from both their electricity and gas bills a year as a result of the measures put in place[300];
- The financial advantage of being able to identify the best deal as a result of these measures persists for four years[301];
- All EU households are able to benefit from these changes equally in relative terms[302];

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296 Note: Weighted base varies by treatment: Best practice = 5,042; Standard = 5,014.

297 As with Option 1, this is a conservative assumption given that 40% more consumers would have access to their unique switching code with every bill (a piece of information important for switching) and significantly more consumers on fixed term contracts are likely to be aware of when their current contracts expired (24% of household consumers report that they only compare tariffs when they needed to renew their contracts). "*Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU*" (2016) European Commission.

298 This assumes the size of improvement in decision making in the real world is as significant as the size of the effect in the experiment. However, many consumers in the real world would not even have access to all the information in the 'standard' bill in the behavioural experiment (see Table 2). The true effect can therefore be expected to be greater.

299 Whilst the behavioural experiment addressed the latter mode of comparison, one of the benefits of this intervention would also be to give consumers easy access to all information relevant to using comparison tools in every bill (switching code, tariff name, consumption).

300 This figure seems proportionate given that the average 80% range of the dispersion of electricity and gas household offers in the market is around EUR 150 (Figure). Assuming that those switching would tend to be moving from a tariff at the more expensive side of this distribution to a tariff at the cheaper side of this distribution, this amounts to saying that the greater market awareness engendered by this intervention would enable consumers to identify an offer that was just c. 3% cheaper than the offer they would have otherwise identified without the intervention.

301 A conservative assumption given the implied average time between switches is upwards of 15.5 years for electricity consumers and 18 years for gas consumers.

- A discount rate of 4% for the consumer benefits year on year;

then Option 2 would result in an increase in consumer surplus **of between 1.8 and 6.5 million euros annually** (depending on the year of implementation), and **55.3 million euros in total for the period 2020-2030**.

However, there is significant uncertainty as to these benefits because it may prove difficult to devise a standard EU comparability box that can fully accommodate all differences between national energy markets. Such as box may downplay the non-quantitative value of energy services (green offers, or offers bundled with home insulation services) when compared to 'plain vanilla' supply contracts. Finally, the prescriptive approach would inhibit beneficial innovation by national regulators and suppliers, and make it difficult to adapt bills to evolving technologies and consumer preferences.

Indeed, the Commission-chaired Working Group on e-Billing and Personal Data Management found that bill design *"should not be imposed by regulation but rather be developed on the basis of better understanding of consumer interests also drawing on the results of behavioural research"*[303].

The **implementation costs** of Option 2 will most likely be significant because:

- All Member States have legislation with billing requirements that are relatively prescriptive, and that will need to be significantly revised (Table 1);
- All energy suppliers would need to significantly revise the design of their household bills in order to comply with the new EU requirements.

This option would therefore result in the following one-time implementation costs to public administrations as well as the 2752 electricity and 1595 gas suppliers in the EU[304]. No running costs are associated with this option due to the computerisation of billing systems.

[302] In reality, households will react differently depending on consumers' needs, skills, motivations, interests, lifestyle, and access to resources such as accurate online comparison tools. However, we have no reliable data to quantify these differences in this specific context.

[303] *Working Group Report on e-Billing and Personal Data Management"*, (2013) Report prepared for the 6th Citizens' Energy Forum, https://ec.europa.eu/energy/sites/ener/files/documents/20131219-e-billing_energy_data.pdf.

[304] Source: CEER National Indicators Database (2015).

Table 8: Option 2 implementation costs (all one-time costs)[305]

Obligation	Action	Entities concerned	Staff type	Hourly rate (EUR)	Man hours	Activity cost (EUR)
Incorporating comparison box into bills	Revising national legislation	28[306]	Legislators, senior officials, managers	41.50	320	371,840.00
	Understanding information obligation	4347[307]	Professionals	32.10	8	1,116,309.60
	Bill design	4347	Professionals	32.10	144	20,093,572.80
					Total	**21,581,722.40**

As regards stakeholder views, Option 2 would not enjoy as much support as Option 1. In particular, it would be resisted by NRAs as well as industry as it would significantly reduce the scope for beneficial innovation by national authorities and suppliers, as well as their ability to tailor information to specific national markets or consumer groups[308]. In addition, whilst consumer groups, the European Parliament and the Committee of the Regions have pushed for greater standardisation of the format of bills, it may prove impossible to devise a format that pleases all of these diverse stakeholders in practice.

Conclusion

Option 1 is the preferred option as it likely leads to significant economic benefits and increased consumer surplus without significant administrative costs or the risk of overly-prescriptive legislation at the EU level.

7.6.6. *Subsidiarity*

Consumers are not taking full advantage of competition on energy markets due, in part, to poor awareness of basic, market-relevant information that could be provided in energy bills.

The Options envisage reinforcing legal requirements on key information to include in consumers' bills. National legal regimes for billing remain fragmented with diverging content and format, and do not always facilitate comparison with offers and pre-contractual information, which would improve switching rates and effectiveness. There is also a need to standardise the definitions of energy costs, network charges, and taxes

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305 Derived from the standard cost model for estimating administrative costs.

306 All Member States. 40 man-days each.

307 All electricity and gas supply companies. 18 man-days each.

308 In a workshop on effective billing that the UK energy regulator, Ofgem, recently held, attendees generally agreed that the level of prescribed information on bills and other communications in the UK is too high, leading to consumers being overwhelmed with information, and that a one size fits all approach doesn't allow for tailored information to be provided to a consumer. See 'Memo: *Effective billing workshop*', (2015) Ofgem, https://www.ofgem.gov.uk/system/files/docs/2016/03/effective_billing_workshop_251115_.pdf.

and levies used in all EU bills in order that consumers understand what they are paying for and are better aware of the extent to which they can control their energy costs.

Well designed and implemented consumer policies with a European dimension can enable consumers to make informed choices that reward competition, and support the goal of sustainable and resource-efficient growth, whilst taking account of the needs of all consumers. Increasing confidence and ensuring that unfair trading practices do not bring a competitive advantage will also have a positive impact in terms of stimulating growth.

The legal basis for the legislative options proposed (Options 1 and 2) is therefore likely to be Article 114 TFEU. This allows for the adoption of *"measures for the approximation of the provisions laid down by law, regulation or administrative action in Member States which have as their object the establishment and functioning of the internal market"*. In doing this, in accordance with Article 169 TFEU, the Commission will aim at ensuring a high level of consumer protection.

Option 0: BAU with stronger enforcement

Business as usual/stronger enforcement does not change the *status quo*. Member States would continue to have a significant degree of discretion in specifying the content of consumers' bills.

From a subsidiarity perspective, this option allows Member States to decide on the extent to which they wish to create an environment where customers are encouraged to switch more freely. If the *status quo* continues, this may not always result in lower overall prices, depending on the national situation.

From the perspective of proportionality, however, this option would not necessarily lead to sufficient improvements in the market.

Option 1: More detailed legal requirements on the key information

The principles of subsidiarity and proportionality are best met through this Option as it is not overly prescriptive and will concretely reduce levels of consumer detriment that are currently not addressed at a national level by all Member State authorities.

This option aims primarily at reinforcing existing legislation but without being overly prescriptive. As billing is already addressed in EU provisions, the subsidiarity and proportionality principles have clearly been assessed previously and deemed as met.

Box 1: Impacts on different groups of consumers

The benefits of the measures contained in the preferred option (Option 1), described in detail in the preceding pages, accrue predominantly to consumers who do not engage in the market or better control their energy consumption because of insufficient billing information or confusing bills. This may include certain vulnerable consumers, or those who are time poor.

Option 2: A fully standardized 'comparability box' in bills

Implementing a standardised comparability box for billing would help to create a level playing field for consumers within Member States and between Member States. At this point, however, it would be disproportionate to impose such a requirement as consumer research in this area is ongoing and current findings are inconclusive.

7.6.7. *Stakeholder's opinions*

Public Consultation
222 out of 237 respondents to the Commission's Consultation on the Retail Energy Market[309] believed that transparent contracts and bills were either important or very important for helping residential consumers and SMEs to better control their energy consumption and costs. 110 out of 237 believed that prices and tariffs that were difficult to compare were a key factor influence switching rates. And 66 out of 133 respondents who thought that bills did not provide sufficient information thought this was the case because they were not sufficiently transparent and meaningful.

43% of all 332 respondents to the Commission's Consultation on the Review of Directive 2012/27/EU on Energy Efficiency[310] think the EED provisions on metering and billing are sufficient to guarantee all consumers easily accessible, sufficiently frequent, detailed and understandable information on their own consumption of energy, versus 32% who opposed this view, and 25% who had no view. Most comments were provided by participants who did not think that the provisions are sufficient. Many argued that energy bills would remain too complex to be properly understood by most customers.

Citizens' Energy Forum, February 2016
The European Commission established the **Citizens' Energy Forum** in 2007. The Forum meets on an annual basis in London and is organised with the support of Ofgem, the UK regulatory authority. The overall aim of the Forum is to explore consumers' perspective and role in a competitive, 'smart', energy-efficient and fair energy retail market. The London Forum brings together representatives of consumer organisations, energy regulators, energy ombudsmen, energy industries, and national energy ministries.

The 8th Citizens' Energy Forum, organised by DG Energy in collaboration with DG Justice, took place in London on Tuesday 23 and Wednesday 24 February. In its conclusions, the forum: *"Call*[ed] *for improved and comparable pre-contractual information, including green offers, contract and billing information to increase consumer engagement."* It addition, the Forum: *"Call*[ed] *for phasing out regulated prices and more clarity on the costs of the components of energy bills to remove barriers to effective competition and allow consumers to choose from more diverse offers."*

European Commission Working Group on e-Billing and Personal Energy Data Management
Including representatives from national NRAs, consumer groups and industry, this **working group** concluded in December 2013 that data presented in e-bills and e-billing information, as well as in paper bills and consumption data presented on paper, needed to be correct, clear, concise and presented in a manner that facilitates comparison and

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[309] Held from 22 to 17 April 2014. https://ec.europa.eu/energy/en/consultations/consultation-retail-energy-market

[310] Held from 4 November 2015 to 29 January 2016. https://ec.europa.eu/energy/sites/ener/files/documents/Public%20Consultation%20Report%20on%20the%20EED%20Review.pdf

provides all relevant information to consumers – including complaint handling and contact points for consumer information e.g. on their energy bills and consumption.

It acknowledged that clear and accurate information on energy consumption, feedback devices, as well as information on historical consumption can help consumers to be better aware of their consumption.

It also suggested that information is presented to consumers in a 'tiered' manner from basic towards more complex data, enabling consumers to look for additional, e.g. more 'technical' data, in an educational manner[311].

National Regulatory Authorities
ACER suggests that there is still a lack of information relevant to switching suppliers on the bill in many Member States. However, it point out that too much information can also lead to too complex bills inhibiting the beneficial role of information to consumers.

The body representing the EU's national regulatory authorities in Brussels, **CEER**[312], points out that detailed requirements can reduce the scope for innovation among suppliers and could become outdated quickly (e.g. there are more people opting for electronic billing). To this end, it feels that minimum standards or slightly higher-level requirements might be more appropriate. It states that understandable billing information as well as readily comparable information are critically important for consumers and welcomes the proposal from the European Commission to identify, in collaboration with national regulators, minimum standards for key information in advertising and bills. It agrees that information on consumption patterns is important for consumers.

The Czech NRA **ERO** states that bills are very difficult to understand, not easy to read and overloaded. Consumers need clear and transparent information, to be able to compare offers, contract termination information, and information for switching.

The French NRA **CRE** suggests that the layout of energy bills should contain two levels: essential / minimal information and detailed information (including where relevant, meter reading, all tariffs, taxes and levies). In a consumer centric model, the exact layout should be the suppliers' responsibility. The breakout pages of the bill might not be relevant in the near future, with the development of web-only / paperless offers. Detailed legislation on paper bills is probably irrelevant in a forward looking perspective, considering the general trend in recurrent billing services. Paper bills should not be made compulsory. Paperless should be promoted as interactive relations allow the supplier to develop a higher competitive advantage.

The UK NRA **Ofgem** does not support prescription beyond ensuring that the key information is presented clearly. The layout of bills should be broadly left to suppliers. Testing and trials is the best route through which to identify the most effective way to present information on bills. It is important to ensure that consumers have access to key

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[311] *Working Group Report on e-Billing and Personal Data Management"*, (2013) Report prepared for the 6th Citizens' Energy Forum, https://ec.europa.eu/energy/sites/ener/files/documents/20131219-e-billing_energy_data.pdf.

[312] The Council of European Energy Regulators.

information and that this is not hidden away. In GB on key communications consumers are presented with a Tariff Information Label (TIL) that houses key information about their tariff and consumption. This provides them with easy access to the information they need to switch tariffs. Ofgem considers this to be a useful/effective tool for consumers. Ofgem has received feedback from a number of sources that consumers find their bills confusing and overly complex.

Consumer Groups

BEUC states that the current EU legislative provisions related to billing are insufficient. Bills should be clear and concise and include the necessary information for the consumer to compare offers and to switch supplier. BEUC welcomes the Commission's plan to put forward proposals to improve the information provided on the bill in order to facilitate comparability and switching among others.

Simpler bills are welcome by consumers. EU legislation should also prescribe the outcomes required for consumers (e.g. that consumers have the data required to switch). As bills are often packed with a lot of information, a way to avoid the overload and simplify the overall bill would be to provide only fundamental elements on the bill (for example in a standardized box). The bill could then include a reference to find more detailed but perhaps less crucial information online.

The first page of the bill should contain specific elements which are standardised. A comparability box showing the key information for switching is needed on the first page of the bill. The Commission should respect the consumer's choice not to play an active role. Clear and accurate bills require high level principles for bills at the EU level. Consumers have a diverse range of preferences and of accessible tools so the approach to information should be shaped by consumer research at the national level. The focus should be on less, simpler and more meaningful is better.

The Swedish consumer group **Konsumenternas** highlights that issues with the bill are often connected to lack of knowledge or understanding the difference between supply and distribution and the respective prices/tariffs. Billing should be subject to competition. Legal provisions on the clarity of bills are difficult to sanction by the regulator. Paper bills are likely to decrease in number and become less relevant.

The Portuguese consumer group **DECO** Highlights that while we already have a standardized information model of pre-contractual information, we don't have the same for energy bills. It could be useful to have a comparability box in the bill, which shows key elements (including energy used compared with previous year, contract end date etc.) and also have information about new promotions and discounts of the same supplier.

DECO believes that some elements that are similar on all energy bills should be standardised at EU level, namely:

1. Energy supplier identification
2. Customer/Consumer identification
3. Invoice date information
4. Invoice number information
5. Commercial supply/services identification (base product/campaign)
6. Specific offer conditions
7. Fees and taxes
8. Bundled Services
9. Payment Methods

10. Social Tariffs/Mechanisms for vulnerable consumers
11. Information about savings/sustainability and energy poverty measures.

Citizens Advice (UK) believes that a comparability box showing the key information for switching is needed on the first page of the bill. EU legislation should prescribe the outcomes required for consumers (e.g. that consumers have the data required to switch). This should be supported by actions to monitor and enforce this (e.g. with a link across to the indicators for market monitoring, including by CEER/ACER). The format and layout should be subject to consumer testing/consumer research. It is useful to provide consumers with information on similar properties in the area but the 'bill' may not be the best location. For instance, the information could be provided in a separate report, sent to the household, outside of the standard billing cycle.

Germany's **VZBV** believes that a clear requirement to show the price per kWh including taxes is missing in the regulation. A requirement to access the meter is missing in the regulation as well. Although legislations exists, these are partly insufficiently implemented from the consumer point of view (esp. in terms of understand ability).

Suppliers
EURELECTRIC states that many consumers across Europe complain that there is too much information on their bills, making them difficult to read. At the same time, regulation does not always allow suppliers to simplify or improve them to fit with specific consumer needs. In a competitive market, bill design should be left to suppliers (and other market parties) to diversify their brand and image. Suppliers also need flexibility to take into account the needs of different groups of consumers. Beside, EURELECTRIC thinks the main issue with bill is not about the "layout" per se but about its "regulated content" (e.g. taxes, legal wording, consumption estimation, etc.). Only the most critical elements could be standardised at national level if evidence suggests this is needed. Consumers also face problems with the high volume of regulated information on their bills. The primary purpose of a bill is to set out charges for energy and to allow the customer to understand how their consumption affects those charges. Giving evidence of how the lay-out of paper bills can create competitive advantage is not an easy thing to do. The point is that different consumer/consumer groups may have different needs and preferences as to what they'd like to see in their energy bill: level of details, format, use of graphs/tables, etc. This is why suppliers should be given enough flexibility to innovate. In any competitive market, differentiation is key to create competitive advantage. EURELECTRIC does not see any evidence which would support the need for further standardisation of elements of the energy bill at European level.

Eurogas states that EU legislation sets prescriptive requirements on billing frequency and use of meter readings which can and should be left to suppliers in competitive markets. Communications should also be able to adapt to changing technology, such as the increasing use of digital media, including smartphones and tablets. Suppliers in competitive markets are best-placed to work out how to engage customers. Graphs and tables may be equally useful in certain situations but it should be up to the competitive market to determine how to present information to customers in an engaging way. Consumers face problems with the high volume of regulated information on bills. The primary purpose of a bill is to set out charges for energy and to allow the customer to understand how their consumption affects those charges. To facilitate the readability of the bill, some information (such as general conditions) could be made available on the dedicated customer area and signposted on the bill.

CEDEC argues that before including new measures in the legislation it should be ensured that the current provisions are respected. New requirements should be conditional on technical feasibility and cost-effectiveness. The focus on measures that are technically feasible and cost effective must remain. Consumers find more difficult to identify and choose the cheapest deal if price structure of electricity offers is complex. In this sense, it would be useful to avoid too many pieces of information.

UK ENERGY highlights that all markets are different and it is the role of competition between market participants to determine what is most effective and appropriate for billing purposes. It believes suppliers need more flexibility to determine what information they provide to customers and how that information is provided with what frequency. Suppliers should have increased flexibility in the layout of the bill since this is one of the few and key contact points to engage with customers. The primary purpose of a bill is to set out charges for energy and to allow the customer to understand how their consumption affects those charges. It is unclear how a standardisation of the first page could keep pace with changing technologies and markets. Consumers increasingly want to receive communication in alternative formats such as online or via apps. It is unclear what benefits standardisation at European level would bring.

The European Parliament
In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the Parliament's **Committee on Industry, Research and Energy (ITRE)**: *"Recommends improving the frequency of energy bills and the transparency and clarity of both bills and contracts in order to aid interpretability and comparison, and to include in or alongside energy bills peer-based comparisons and information on switching; insists that clear language must be used, avoiding technical terms; requests the Commission to identify minimum information requirements in this respect, including best practices; stresses that both fixed charges and taxes and levies should be clearly identified as such in the bills, allowing the customer to distinguish them easily from the variable, consumption-related cost; recalls existing requirements for suppliers to specify in or with bills the contribution of each energy source to the overall fuel mix of the supplier over the preceding year in a comprehensible and clearly comparable manner, including a reference to where information can be found on the environmental impact in terms of CO_2 emissions and radioactive waste. Recommends that consumers should be notified in or alongside energy bills about the most suitable and advantageous tariff for them, based on historic consumption patterns, and that it should be possible for consumers to move to that tariff, if they so wish, in the simplest way possible. Considers that incentives and access to quality information are key in this respect and asks the Commission to address this in upcoming proposals."*

In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the Parliament's **Committee on the Internal Market and Consumer Protection (IMCO)** called for: *"the Commission to take further action to improve the frequency of energy bills and the associated meter readings, and their clarity, comparability, and transparency as regards types of energy sources, consumption, price structure and the processing of enquiries and complaints."*

The Committee of the Regions
In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the **Committee of the Regions**:

- calls on the European Union to examine the different components of energy bills, in order to put together a "standard" bill incorporating a number of elements that are uniform, legible, clear and comparable at European level and which would allow consumers to optimise their energy use. In this regard, the European Committee of the Regions supports the Council of European Energy Regulators' initiative to set out harmonised definitions of different elements that should be included in energy bills;

- calls for standardisation to be accompanied in the final bill by information about the free tools and services that are available for comparing supply offers, as well as information and support for households and businesses with regard to the protection of consumers' rights;
- calls on Member States to create tools and services that make bills easier for households and businesses to understand, so that they can be analysed; and, where appropriate, to provide advice and support for end-users regarding the steps which may be necessary to rectify any irregularities identified or guide end-users towards supply contracts that are better suited to their needs;
- recommends that bills and any information issued by suppliers to their end-users should be sent in the format requested by the latter, i.e. via post or e-mail, without any discrimination;
- stresses that vulnerable consumers are particularly likely to encounter difficulties in identifying the best tariffs amongst the wide range of offers, and that they often seek the assistance of the closest level of governance. Consequently, the European Committee of the Regions calls upon the European Union to assist local and regional authorities in setting up support systems in the field of energy if this is not being done by the Member States.

8. Description of relevant European R&D projects

Technological developments are both part of the drivers that affect the present initiative and part of the solutions of the problems they affect.

Technological developments have created the opportunities for consumers to transit from being passive consumers of electricity to prosumers that can actively manage their consumption, storage and production of electricity and particiapte in the market. This provides opportunities for innovative business models of service provisions, often based on advanced technologies, based on enabling smaller consumers and distributed generation to interact with the market and have their resources being managed. At the same time, networks should be managed more actively in order to meet the challenges more decentralised generation brings about.

As the transition path is also created by technological progress and the solutions to the problems they entail are equally shaped by technology, the present annex provides for a sample of projects, supported by the EU through its 6th and 7th Framework Programme and Horizon2020, that have developed technologies and innovations that render these developments more concrete but also provide insights as to the direction the transition may take.

Project FP7-DISCERN

Title: Distributed Intelligence for Cost-Effective and Reliable Distribution Network Operation

The project linked with six large-scale smart grids demonstration projects financed at national level. The project developed methods to characterise outcomes and aimed to find ways to replicate solutions from one country to another.

Fact Sheet: http://cordis.europa.eu/project/rcn/106040_en.html

Web Site: http://www.discern.eu/

Important project outcome include:

The practical testing and tuning of performance metrics (Key Performance Indicators – KPI) and evaluation of their values based on actual measurements. The project concludes that use of the KPI framework is a valid approach for revealing the impact of a technical solution and its function(s) on a DSO grid, system or organisation and to set the expected set of outcomes. These can be used to analyse cost/benefit ratios at design stage and after implementation. Cost KPIs are a valid method for assessing cost structures for Use Cases, however as the creation of a common cost list to support impartial comparisons of the various Use Cases was found impractical within the constraints of DISCERN, the evaluation of costs and determination of initial investments relied on individual Use Case information, which by its nature incorporates company specific cost drivers

Project FP7-ITESLA

Title: Innovative Tools for Electrical System Security within Large Areas

The project developed methods and tools for the coordinated operational planning of power transmission systems, to cope with increased uncertainties and variability of power flows, with fast fluctuations in the power system as a result of the increased share of resources connected through power electronics, and with increasing cross-border flows. The project aims at enhancing cross-border capacity and flexibility while ensuring a high level of operational security.

Fact Sheet: http://cordis.europa.eu/project/rcn/101320_en.html
Web Site: http://www.itesla-project.eu/

Important project outcomes include:

- a platform of tools and methods to assist the cooperation of transmission system operators in dealing with operational planning from two days ahead to real time, particularly to ensure security of the system. These tools support the optimisation of security measures, in particular to consider corrective actions, which only need to be implemented in rare cases that a fault occurs, in addition to preventive actions which are implemented ahead of time to guarantee security in case of faults. The tools provide risk-based support for the coordination and optimisation of measures that transmission operators need to take to ensure system security. The platform also supports "defence and restoration plans" to deal with exceptional situation where the service is degraded, e.g. after storms, or to restore the service after a black-out. The platform has been made publicly available as open-source software.
- A clarification of the data and data exchanges that are necessary to enable the implementation of these coordination aspects.
- A framework to exchange dynamic models of power system elements including grids, generators and loads, and a library of such models covering a wide range of resources. These models are essential to produce accurate prediction of the rapid fluctuations that take place in the power grid after faults, and to prevent cascading failures.
- The tools and models allow to reduce the amount of necessary preventive measures. The reliance on risk-based approaches can avoid or mimimise costly preventive measures such as re-dispatching while the overall risk of failure is decreased.
- A set of recommendations to policymakers, regulators, transmission operators and their associations (jointly with the UMBRELLA project). These foster the harmonisation of legal, regulatory and operational framework to allow the exploitation of the newly developed methods and tools. They also

identify the need for increased formalised data exchange among TSO's to support the new methods and tools.

Project FP7-UMBRELLA

Title: Toolbox for Common Forecasting, Risk assessment, and Operational Optimisation in Grid Security Cooperations of Transmission System Operators (TSOs)

The project developed methods and tools for the coordinated operational planning of power transmission systems, particularly to cope with high shares of variable renewable energy. They aimed at enhancing cross-border capacity and flexibility while ensuring a high level of operational security.

Fact Sheet: http://cordis.europa.eu/project/rcn/101318_en.html
Web Site: http://www.e-umbrella.eu/

Important project outcomes include:

- The demonstration of probabilistic forecasting of power generation and power flows on a regional basis. These are important to plan ahead of time, the most effective methods for relieving expected congestions. Such forecasts will also be important for intraday trading on wholesale markets.
- Validated methods and tools for a coordinated optimisation of measures to ensure the security of the pan-European grid. Of particular importance is the to coordination of measures for relieving expected congestions, starting from low-cost measures such as switches to coordinated generation redispatching.
- The tools and models allow to reduce the amount of necessary preventive measures. The reliance on risk-based approaches can avoid or mimimise costly preventive measures such as re-dispatching while the overall risk of failure is decreased.
- a set of recommendations to policymakers, regulators, transmission operators and their associations (jointly with the ITESLA project). These foster the harmonisation of legal, regulatory and operational framework to allow the exploitation of the newly developed methods and tools. They also identify the need for increased formalised data exchange among TSO's to support the new methods and tools.

Project FP7-eHIGHWAY2050

Title: Modular Development Plan of the Pan-European Transmission System 2050

The project developed new methods for the top-down long-term foresight of the power system infrastructure in a 2050 perspective, and applied these to depict grid requirements under a number of scenarios, and outlined a "future proof" modular development pathway to this horizon.

Fact Sheet: http://cordis.europa.eu/project/rcn/106279_en.html
Web site: http://www.e-highway2050.eu/e-highway2050/

Important project outcomes include:

- a number of basis scenarios framing possible evolution of demand, generation and delivery infrastructure in the 2050 perspective
- a foresight of expected power system technology evolution in this time frame
- optimised grid architectures to efficiently respond to the delivery needs for each of the selected scenarios
- a modular development plan with intermediate steps that largely fit all the future pathways
- new methods for optimal long-term planning of power systems in the presence of major uncertainties
- a well-documented proposal for the clarification of the concept of "electricity highways" in the context of the EU energy infrastructure package. This proposal has largely been adopted in the process of selecting the second round of "projects of common interest" and has resulted in a substantial number of projects identified as "electricity highways" as part of a double label.

Project FP6 : VSYNC –

Title: Virtual Synchronous Machines (VSG's) For Frequency Stabilisation In Future Grids with a Significant Share of Decentralized Generation.

The project developed methodologies to enable a generator to behave like a "*Virtual Synchronous Generator*" (**VSG**) during short time intervals and contribute to the stabilisation of the grid frequency.

Cordis website: http://cordis.europa.eu/project/rcn/85687_en.html

Project website: http://www.vsync.eu/

Important project outcomes include:

- The Virtual Synchronous Generator technology can contribute to the stabilisation of the grid frequency at distribution level. The Vsync technology could allow PV to provide balancing services replacing the inertia of 'traditional' generators. As a result, the RES absorption capacity of the grid is increased.
- Today frequency control is handled by TSOs mainly with the help of generators connected to the transmission network. The provision of Ancillary Services of assets connected to the distribution grid is currently not standard practice and is not standardized. However, it is possible that these will be required or offered in future, due to increased system needs, increasing share of decentralized generation (also reducing the possibility to rely exclusively on large generation) and possible connection and reinforcement cost optimization at distribution..

IEE project REServiceS –

Title: Economic grid support from variable renewables

RESERVICES addresses changes in the future European power system:, in particular the need for development of an ancillary services market in which RES can participate.

IEE website: http://ec.europa.eu/energy/intelligent/projects/en/projects/reservices

Project website: http://www.reservices-project.eu/

Important project outcomes include:

- **Ancillary services** are grid support services required by the power systems (transmission or distribution system operators TSOs or DSOs) to maintain integrity, stability and power quality or the power system (transmission or distribution system). Ancillary services can be provided by connected generators, controllable loads and/or network devices. Some services are set as requirements in Grid Codes and some services are procured as needed by TSOs and DSOs to keep the frequency and voltage of the power system within operational limits or to recover the system in case of disturbance or failure.
- There are different procurement and remuneration practices for Ancillary services, and these practices are evolving. There are already markets for some services. Some services are mandatory (not necessarily paid for) and some services are subject to payments according to regulated (tariff) pricing or tendering process and competitive pricing.
- RES (in particular PV and wind) can provide ancillary services both at DSO and TSO level, from a technology point of view, but due to the way the markets are defined (and the way ancillary services are managed) in practice they cannot participate.

Project FP6 Integral

Title: Integrated ICT-platform based Distributed Control in electricity grids with a large share of Distributed Energy Resources and Renewable Energy Sources.

The INTEGRAL project demonstrated how Distributed Energy Resources and Demand Side Response in the distribution grid can be controlled and coordinated, based on commonly available ICT components, standards and platforms. The project treated the operating conditions of the grid with DER/RES aggregations in three different operating conditions:

- Normal operating conditions of DER/RES aggregations – Stakeholders involved: consumers, aggregators, utilities.
- Critical operating conditions of DER/RES aggregations – Stakeholders involved: consumers, DSO
- Emergency operating conditions – Stakeholders involved: DSO

Cordis website: http://cordis.europa.eu/project/rcn/86362_en.html

Project website: http://integral-eu.com/

Important project outcomes include

- The test field A of the INTEGRAL project (grid in normal operational conditions), the PowerMatching City, demonstrated that the control of DER through an automated market based concept by means of "agents" distributed in the grid and the Powermatcher application, satisfies the needs of consumers, aggregators and DSO. On the Data and communication aspects, the project demonstrated the absence of technological barriers as public networks were used for transport of private data by means of Virtual Private Networks (VPN), a proven technology to transfer encrypted data.
- The test field B (critical operation of the grid) demonstrated that DSO or aggregators can control the grid through controlling loads and generation of prosumers. Under critical conditions, the Demand Side Management (DSM) system disconnects the critical loads.
- The test field C (emergency operation of the grid) demonstrates that the self-healing concept helps to minimize the average outage time of the grid. It is a high automation levels that allows DSO reducing the average number of interruptions, enhancing hence the service quality of the grid.

Project FP7 SuSTAINABLE

Title: Smart distribution System operaTion for mAximising the Integration of renewable generation

The SuSTAINABLE project developed and demonstrated the efficient and cost-effective management of the grid with high penetration of RES configured as a virtual power plant through elaboration of data related to load forecast, grid infrastructure protection and renewable energy production forecast.

Cordis website: http://cordis.europa.eu/project/rcn/106534_en.html

Project website: http://www.sustainableproject.eu/Home.aspx

Important project outcomes include:

- Concerning data management, the project demonstrated that intelligent management supported by more reliable load and weather forecast can optimise the operation of the grid. The results show that using the distributed flexibility provided by DRD – Dynamic Response of Demand can bring an increase of RES penetration while, at the same time, avoiding investments in network reinforcement.
- Concerning DSO benefits, the results of the project demonstrated that the active management of the renewable generation can lead to a decrease in the investment costs of distribution lines and substations.

<u>Project FP7 IDE4L</u>

Title: Ideal Grid for All

The IDE4L project focuses on

- improving distribution network monitoring and controllability by introducing hierarchical decentralized automation solution for complete real-time MV and LV grid management,
- utilizing existing distribution networks more efficiently and managing fast changing conditions by integrating large number of distributed energy resources in distribution network through real-time automation and market based flexibility services,
- guaranteeing continuity and quality of electricity supply by distributed real-time fault location, isolation and supply restoration solution cooperating with microgrids, and
- improving visibility of distributed energy resources to TSOs by synthesizing dynamic information from distribution system and to commercial aggregators by validating and purchasing flexibility services.

Cordis website: http://cordis.europa.eu/project/rcn/109372_en.html

Project website: http://ide4l.eu/

Important project outcomes include:

- Concerning data management and interoperability, the project aims to create a single concept for distribution network companies to implement active distribution network today based on existing technology, solutions and future requirements.
- All data exchange and data modelling are based on international standards IEC 61850, DLMS/COSEM and CIM to enable interoperability, modularity, reuse of existing automation components and faster integration and configuration of new automation components.

IDE4L develops the entire system of distribution network automation, IT systems and functions for active network management.

- Fault location, isolation and supply restoration
- Congestion management
- Interactions between distribution and transmission network companies

<u>Project FP7 NRG4Cast</u>

Title: Energy Forecasting

NRG4Cast project developed advanced solutions for predicting behaviour of local energy networks for the three functions:

- Predicting energy demand on several network granularity levels (region, municipality, city, business, household and energy service provider),
- Predicting energy network failures on interlinked local network topologies,

Detecting short-term trends in energy prices and long-term trends in national and local energy policies.

Cordis website: http://cordis.europa.eu/search/result_en?q=nrg4cast

Project website: http://www.nrg4cast.org/

Important project outcomes include:

- From the data collection point of view, the project demonstrates (as other similar projects) that the optimization of the use of energy (and hence a higher business margin) in a distributed generation can be achieved with the support of IT dedicated tools. DSOs as well as other actors (utilities, municipalities, etc.) can use these tools in their activities.

<u>Project FP7 EEPOS</u>

Title: Energy management and decision support systems for Energy Positive neighbourhoods

EEPOS is a central energy management system for neighbourhoods that performs coordinated energy management. Additionally, it actively participates in energy trading with external parties on behalf of the neighbourhood members.

Cordis website: http://cordis.europa.eu/project/rcn/105854_en.html

Project website: http://eepos-project.eu/

Important project outcomes include:

- Regarding the right to self-produce, consume, store electricity and use flexibility, optimization of use of energy use can be achieved at neighbourhood or district level more effectively than at household level through ad hoc energy management systems (IT support as other similar projects).
- Consequence: Matching supply and demand automatically relieves grid unbalance providing hence indirectly grid services.

<u>H2020:</u> BRIDGE project network

The BRIDGE initiative collects policy recommendations from the use cases which are currently under demonstration in the ongoing H2020 energy projects.

Important findings for the market design initiative:

Balancing:

- barriers on access to the balancing market. It is observed that not all markets in practice allow load to be included. This is discriminatory for the energy storage assets demonstrated in the projects and does not allow the correct valorisation of their double operative nature.

Ancillary services:

- barriers on access to the ancillary market. Participants in the project include Energy Service companies that provide e.g. Frequency Response, Congestion management, Reserve and Ramping Duty. It is recommended that products for ancillary services should be consistent and standardized from transmission and down to the local level in the distribution network. Such harmonization will increase the availability of the services, enable cross-border exchanges and lower system costs.

<u>Project H2020:</u> SMARTNET

Title: Smart TSO-DSO interaction schemes, market architectures and ICT Solutions for the integration of ancillary services from demand side management and distributed generation

The project SmartNet aims at providing architectures for optimized interaction between TSOs and DSOs in managing the exchange of information for monitoring and for the acquisition of ancillary services (reserve and balancing, voltage regulation, congestion management) both at national level and in a cross-border context.

Cordis web site: http://cordis.europa.eu/project/rcn/200556_en.html

Project web Site: http://smartnet-project.eu/

Important project outcomes include:

- Validated acquisition of ancillary services from specific resources such as thermal inertia of indoor swimming pools and batteries in telecommunication base systems. In addition the project will demonstrate modalities to exchange monitoring signals between transmission and distribution networks. The architectures for dataflow and control signals will be tested in full replica lab considering various levels of responsibilities for the DSOs. These ranges from a model with extended central dispatch where TSO contracts ancillary services directly from DER owners connected to the DSO grid to a more decentralized model where TSO, DSO and BRPs contract ancillary services connected at distribution level for their own need in a common market. The preferential architectures and data flow models will be defined during the course of the project that is running until the end of 2018.

Project FP7: ECOgrid-EU

Title: Large scale Smart Grids demonstration of real time market-based integration of DER and DR

ECOGRID-EU is a large-scale demonstration project which included 1,900 test households, out of which ~1,200 houses were equipped with home automation equipment and 500 were manually controlled households. The project focused on direct (resistance based) and indirect (heatpump) electricity heating applications for households since these has the highest volume potential for demand response

Cordis web site: http://cordis.europa.eu/project/rcn/103636_en.html

Project web Site: http://www.eu-ecogrid.net/

Important project outcomes include:

- Dynamic pricing needs a short time-interval, i.e. 15 minutes or less. It shows as well that this is technically possible: even a 5-minute period is technically possible although not cost-effective in the project setting.
- The FP7 project ECOGRID has successfully demonstrated a "real time" power market concept with 5 min time resolution. The concept provides the customers with real time prices and the local ICT control system in the houses make it possible to optimize the use of electricity by automated adjustment of the consumption. The concept included both a global price signal for balancing and a locational price signals for congestion management, although the latter wasn't fully validated. In the basic concept of the EcoGrid EU project, control of active power is generally done by leveraging the global real-time market price and its corresponding forecast. Based on this, price deviations for each of the local areas can be computed in order to relief active power issues within that area. The ICT concept consists of a new market place and local control schemes which are implemented by three different technology vendors, thereby allowing a wider base of appliances.
- It showed as well the importance of a reliable communication and automation channel, in particular for 'legacy equipment' (i.e. already installed heat pumps or electric heating).
- An important learning was that automated control has responded much better to price signals than manually controlled. A customer with manual control gave a 60 kW total peak load reduction while automated or semi-automated customers gave an average peak reduction of 583 kW.
- For the households equipped with fully automated demand response, the communication interface was the highest share of the equipment cost, but in future these costs could be virtually zero when appliances are cloud connected anyway.
- For the demonstration area (Bornholm in Denmark) wind power curtailment (virtually) was reduced by almost 80%, and the use of (virtual) spinning reserves has been reduced by 5.5%.
- In the replication roadmap it is shown that the Belgian market could give a EUR 2 million/year reduction of balancing cost if 10%, of the 18% of the households that have a hot water buffer tank, is used for demand response.

Project FP7 Grid4eu

Title: Large-Scale Demonstration of Advanced Smart GRID Solutions with wide Replication and Scalability Potential for EUROPE

Grid4EU aims at testing in real size some innovative system concepts and technologies in order to highlight and help to remove some of the barriers to the smart grids deployment and the achievement of the 2020 European goals. It focuses on how distribution system operators can dynamically manage electricity supply and demand, which is crucial for integration of large amounts of renewable energy, and empowers consumers to become active participants in their energy choices. It is organized around large-scale demonstrations networks located in six different countries,

Cordis web site: http://cordis.europa.eu/project/rcn/103637_en.html

Project web Site: http://www.grid4eu.eu

Important project outcomes include:

- Demonstration of enhanced functionalities of Online Tap Change Transformers (OLTC) that will enable higher levels of PV to be integrated in the downstream LV grid. This function consists in fine-tuning the voltage set point according to a set of parameters and inputs that includes real-time solar radiation, used as an indicator of the amount of PV energy being produced. This enhanced control allows varying the voltage set point that takes into account the amount of PV energy being produced, including reaction to real time perturbations (e.g. temporary reduction in PV production due to a cloud).
- Demonstration of technical viability of islanding in a segment of a distribution network to alleviate e.g. critical situations at TSO level.
- Demonstration of the "Network Energy Manager (NEM) that provides an integrated flexibility marketplace for the TSO and DSO to specify their flexibility needs to solve their respective grid operational constraints. These needs can be automatically computed by the NEM based on renewable production forecasts and individual load forecasts. The NEM also provides a portal for various DER and flexibility aggregators to offer their flexibility services to satisfy the requests. As a result, the NEM performs a global optimisation to address needs in the most economical way while still enforcing the technical constraints. This fully automated process notifies the aggregators of their awarded flexibility for implementation and activation for demand response, load shifting or storage device dispatch.

Project H2020: Futureflow

Title: Smart TSO-DSO interaction schemes, market architectures and ICT Solutions for the integration of ancillary services from demand side management and distributed generation

FutureFlow links interconnected control areas of four transmission system operators of Central-South Europe which today do face increasing challenges to ensure transmission system security: the growing share of renewable electricity units has reduced drastically the capabilities of conventional, fossil-fuel based means to ensure balancing activities and congestion relief through redispatching. Research and innovation activities are proposed to validate the enabling conditions for consumers and distributed generators to provide balancing and redispatching services, within an attractive business environment.

Cordis web site: http://cordis.europa.eu/project/rcn/200558_en.html

Project web Site: http://www.futureflow.eu/

Important project outcomes include:

- The project Futureflow will demonstrate in near-to-real-life conditions that balancing and redispatching service providers are able to provide cross-border balancing and redispatching services to control zones outside their Member State borders, including automatic frequency restoration reserve services. Each transmission system operator connected to the regional platform is able to perform its activities by using the offers from generators and consumers possibly located in the control area of another transmission system operator also connected to the regional balancing and redispatching platform.

Project FP7-AFTER

Title: A Framework for electrical power sysTems vulnerability identification, dEfense and Restoration

The AFTER project addresses the challenges posed by the need for vulnerability evaluation and contingency planning of the energy grids and energy plants considering also the relevant ICT systems used in protection and control. Project emphasis is on cascading events that can cause catastrophic outages of the electric power systems.

Cordis web site: http://cordis.europa.eu/project/rcn/100196_en.html

Project web Site: http://www.after-project.eu

Important project outcomes include:

- The FP7 project AFTER has developed a framework for electrical power systems vulnerability identification, defense and restoration. It uses a large set of data (big data) coming from on-line monitoring systems available at TSOs' control centres. A fundamental outcome of the tool consists in risk-based ranking list of contingencies, which can help operators decide where to deploy possible control actions.

Project FP7-SESAME

Title: Securing the European Electricity Supply Against Malicious and accidental threats

SESAME develops a Decision Support System (DSS) for the protection of the European power system and applies it to two regional electricity grids, Austria and Romania.

Cordis web site: http://cordis.europa.eu/project/rcn/98988_en.html

Project web Site: https://www.sesame-project.eu/

Important project outcomes include:

- SESAME, developed a comprehensive decision support system to help the main public actors in the power system, TSOs and Regulators, on their decision making in relation to network planning and investment, policies and legislation, to address and minimize the impacts (physical, security of supply, and economic) of power outages in the power system itself, and on all affected energy users, based on the identification, analysis and resolution of power system vulnerabilities.

Project H2020: Nobelgrid

Title: New Cost Efficient Business Models for Flexible Smart Grids

NOBEL GRID will develop, deploy and evaluate advanced tools and ICT services for energy DSOs cooperatives and medium-size retailers, enabling active consumers involvement –i.e. new demand response schemas – and flexibility of the market – i.e. new business models for aggregators and ESCOs.

Cordis web site: http://cordis.europa.eu/project/rcn/194422_en.html

Project web Site: http://nobelgrid.eu/

Important project outcomes include:

- The H2020 project NOBEL Grid will develop, deploy and evaluate advanced tools and ICT services for energy DSOs cooperatives and medium-size retailers, enabling active consumers and prosumers involvement. Particularly for domestic and industrial prosumers they will develop an Energy Monitoring and Analytics App. Demonstration and validation of the project solutions will be done in real conditions in five different electric cooperatives and non-profit sites in five EU members' states.

Project FP7-S3c

Title: Smart Consumer - Smart Customer – Smart Citizen

The S3C project's overall objective is to foster the 'smart' energy behaviour of energy customers in Europe by assessing and analysing technology and user-interaction solutions and best practices in scientific literature, test cases and pilot projects. Based on these insights, the S3C consortium has developed a practical toolkit for everyone who is involved or intends to become involved in the active engagement of end users in smart energy projects or rollouts.

Cordis web site: http://cordis.europa.eu/project/rcn/105831_en.html

Project web Site: http://www.s3c-project.eu/

Important project outcomes include:

- The project suggests that energy system actors (e.g. DSOs, suppliers, ESCOs, regulators) must adapt the way and the content of their communication with customers and citizens, taking into account the diversity of consumer segments with different backgrounds and needs. The content of communication must be transformed into something more visual, tangible and understandable, showing exactly the benefits customers may experience (e.g. saved money, reduction of CO_2 emission) instead of a purely technical information.

Project FP7-metaPV

Title: Metamorphosis of Power Distribution: System Services from Photovoltaics

The goal of the demonstrator was to explore in real life how PV systems can provide grid services for increasing the hosting capacity of existing grids. This was pursued by adding a significant amount of controllable inverters to a confined grid where the PV penetration was high already before. The demonstrator is split up in a low voltage (LV) and a medium voltage (MV) part. On LV, the project aimed to convince 128 households' consumers to install PV systems of an average PV generation capacity of 4 kW, for a total of 512 kW. On MV, the target was to realise 31 installations of on average 200 kW, for a total of 6,2 MW, located at commercial and industrial sites connected to the MV grid.

Notably, all PV inverters generate low voltage at their output; however, the so-called MV systems are directly connected to the medium voltage grid through a transformer..

Cordis web site: http://cordis.europa.eu/project/rcn/94493_en.html

Project web Site: http://metapv.eu

Important project outcomes include:

- MetaPV demonstrated that remotely controllable inverters connecting PV-panels to the distribution grid can offer congestion management services to the distribution grid (in the form of voltage control obtained via reactive power modulation).
- For medium-voltage grids, the hosting capacity of the network can be increased by more than 50% at the cost of 10% of traditional grid reinforcement. For low-voltage grids, the same is also possible as long as the costs of sophisticated features for communication do not eat up the savings from the substituted grid reinforcement.

In MetaPV, the household received a commercial offer for the demonstrator. This offer was attractive, partly because the inverter was offered by the inverter manufacturer at the cost (not price). DSO paid for additional equipment needed (like hardware for data logging and communication, batteries, etc.). In exchange, the customers acknowledged that the installations made part of a demonstration and that DSO had the right to control them from time to time.

- MetaPV suggests that DSO makes a multiannual investment plan that takes into account flexibility (MetaPV suggests to do this through a cost-based analysis).
- The case of MetaPV raises the question if the DSOs have the right to use or impose functions to the customers where the PV inverters are placed. Direct control over the inverter is only granted (in special cases) in Austria and Germany whereas in several countries DSO can impose functions to PV inverters.

Project FP7-INTrEPID

Title: INTelligent systems for Energy Prosumer buildings at District level

INTrEPID developed technologies that enable energy optimization of residential buildings, allowing control of internal sub-systems within the Home Area Network and interaction with other buildings, local producers, and electricity distributors, as well as enabling energy exchange capabilities at district level. The project had three main objectives: A. Energy optimization, which is provided by the development of three

INTrEPID technological components (Indoor Home networks, Supervisory control strategies and Energy Brokerage); B. Integration and validation of the integrated system. C. Dissemination and Exploitation.

Cordis web site: http://cordis.europa.eu/project/rcn/105992_en.html

Project web Site: http://www.fp7-intrepid.eu/ intrepid@telecomitalia.it

Important project outcomes include:

- A methodology to extract individual power consumption of home appliances with a measurement at a single point, using non-intrusive load monitoring (NILM) has been developed. NILM algorithms utilize machine learning to detect and extract features from the aggregated consumption data. For the households considered in the INTrEPID project, the algorithm disaggregates the individual consumption of major appliances, without the added cost of an individual meter per device. The tested algorithm performs well in the experiments and delivers on its promises in simple settings, where the models account for all of the loads. However, in the final scenario, the algorithm has to give up due to lack of models and detailed datasets. Producing the Markov models for the algorithm proves to be the biggest disadvantage of the algorithm. Attempts were made to construct these by manual inspection of the dataset, which did prove to be quite successful. However, it was necessary to make assumptions about the states of the refrigerator. For the general case this works quite well, but the possible defrost cycle was not taken into account, and only one program in the dish washer was considered. This indicates that exhaustive knowledge about the appliance is required, when reasoning about the number of states and transitions.
- This project shows that direct access to the meter should be considered for other parties to be able to develop innovative services based on NILM algorithm. It is therefore not good for innovation if all information from the smart meter has to go via the DSO first.
- The project also demonstrates that there are further dimensions to investigate when considering the data customer confidentiality

Project FP7- INCREASE

Title: Increasing the Penetration of Renewable Energy Sources in the Distribution Grid by Developing Control Strategies and using Ancillary Services

INCREASE focuses on how to manage renewable energy sources in LV and MV networks, to provide ancillary services (towards DSO, but also TSOs), in particular voltage control and the provision of reserve. INCREASE investigates the regulatory framework, grid code structure and ancillary market mechanisms, and propose adjustments to facilitate successful provisioning of ancillary services that are necessary for the operation of the electricity grid, including flexible market products

Cordis web site: http://cordis.europa.eu/project/rcn/109974_en.html

Project web site: http://www.project-increase.eu/

Important project outcomes:

- The market access for aggregators is improving in some EU countries, while others are still lagging behind. Often the regulatory frameworks are not supportive for demand response or participation of distributed renewable generation.
- Important adjustments of market regulations can be observed in a few countries, namely the reduction of the minimum bid sizes to allow small renewable generations to participate in tenders, and shorter scheduling periods. However in several EU countries no suitable frameworks to enable participation of flexibility aggregators yet exist.

Project FP7- evolvDSO

Title: Development of methodologies and tools for new and evolving DSO roles for efficient DRES integration in distribution networks

With the growing relevance of distributed renewable energy sources (DRES) in the generation mix and the increasingly pro-active demand for electricity, power systems and their mode of operation need to evolve. evolvDSO will define future roles of distribution system operators (DSOs) and develop tools required for these new roles on the basis of scenarios which will be driven by different DRES penetration levels, various degrees of technological progress, and differing customer acceptance patterns.

Cordis web site: http://cordis.europa.eu/project/rcn/109548_en.html

Project web Site: http://www.evolvdso.eu/

Important project outcomes include:

- DSOs can create additional value by offering/using services to/from different stakeholders in the interest of the entire power system and its users. A sound regulatory framework can support them in these activities.
- Future markets and regulatory frameworks should recognize the need and should provide incentives for possible innovative flexibility levers to be procured and activated on distribution grid level. Different stakeholders may benefit from these flexibility levers. DSOs may need these services in different timeframes as alternatives for grid investment (long-term ahead, procured via tender) and/or conventional operational planning actions (short-term ahead, procured via a (flexibility) market platform). DSOs will have to gradually increase their network monitoring capacities, as well as their active involvement in flexibility services.

Future regulatory frameworks should set clear rules for the recognition of the costs (both CAPEX and OPEX, over all timeframes) associated with innovative smart grid solutions, taking into account their interaction with conventional solutions and the uncertainty on cost recovery.

- Future regulatory frameworks should continue to safeguard the availability of neutral, secure, cost-efficient and transparent data and information management on distribution grid level for all concerned stakeholders.
- Future electricity markets will need to take into account the location of system flexibility sources and their impact on distribution grids.

Project FP7- DREAM

Title: Distributed Renewable resources Exploitation in electric grids through Advanced heterarchical Management

DREAM is working on an innovative organisational and technological approach for connecting electricity supply and demand. Heterarchical principles, in which coordination is configurable, are used to coordinate users, producers and technical/commercial/financial operators to achieve benefits. These are expected to well exceed the technological investments required to final users. This will be pursued also through the introduction of a new layer in the energy market, placed at distribution level and allowing for cost-effective dynamic aggregations of users and local exchange/sales of capabilities (e.g. ancillary services from shed-able loads or from time-flexible use of electric power), while ensuring integration with upper level national energy marketplaces and their international interactions..

Cordis web site: http://cordis.europa.eu/project/rcn/109909_en.html

Project web Site: http://www.dream-smartgrid.eu/

Important project outcomes include:

- The intrinsic control capability made available at distribution network level through the innovative heterarchical paradigm of DREAM, will accommodate for improved real time local balancing of energy demand and provision, thus limiting the request of voltage and frequency regulation capacity at transmission and distribution control level.
- The net effect of additional local balancing capacity will be reflected into a reduction of network reinforcement requirements, and thus will increase the allowance for safe management of renewable and distributed energy resources at the same level of deployed reinforcements.

Project FP7-PlanGridEV

Title: Distribution grid planning and operational principles for electric vehicles mass roll-out while enabling integration of renewable distributed energy sources.

The increasing number of electric vehicles (EVs) (and their batteries) on the one hand and of distributed energy sources (DER) on the other, both connected to the low-voltage (LV) and the medium-voltage (MV) grid, are a major challenge for Distribution System Operators (DSOs) with regard to secure and reliable energy supply and grid operation. The project developed a planning tool for DSOs which copes with this new challenge and facilitates the transformation of the grid towards a smart grid (with controllable loads). With the help of the tool, investment strategies regarding the reinforcement of infrastructures can be downsized while the service quality and efficiency can be improved at the same time (reduction of peak loads and increased renewable energy supply). PlanGridEV developed architectures to build smart grids that support a successful and economical rollout of charging infrastructure. In addition to paving the way into a new way of mobility these architectures are able to activate new markets where the costumers' (EV users) can participate and benefit from (change from costumer to prosumer e.g. by offering battery capacity for grid stability services).

Cordis web site: http://cordis.europa.eu/project/rcn/109374_en.html

Project web site: http://www.plangridev.eu/

Important project outcomes include

- The new planning tool for DSOs: it considers the controllability of the loads (i.e. EVs) with the (estimated) electricity generation from renewable resources;
- Tests with controllable loads DER performed in a large variety of grid constellations have shown that peak loads could be reduced (up to 50%) and more renewable electricity could be transported over the grid compared to scenarios with traditional distribution grid scenarios; as a result, critical power supply situations can be avoided, and grids, consequently, do not call for reinforcement;
- Smart grids on LV/MV level require the introduction of more information and communication technologies (ICT) allowing the exchange of operation data and control schemes between independent market actors. PlanGridEV outlines changes of the regulatory framework allowing for a new market design embedded within a roadmap and tangible recommendations for (i) industry, (ii) grid operators and service providers, (iii) policy makers, and (iv) regulators with the aim that investments in grid intelligence can be rewarded via modified tariff systems and market borders can be broken down.