COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT

Accompanying the document


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 on risk preparedness in the electricity sector

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INTRODUCTION

This document contains annexes to the impact assessment and are an integral part of thereof.

More in particular, it contains a description and assessment of the detailed measures that are grouped and assessed under each option in the main body of the impact assessment.

It also contains an annex on relevant European R&D projects, which provided the basis for the R&D related boxed in the main document.

For ease of access, reference is made to the table of contents on the next pages and the summary tables placed at the start of each chapter. The glossary and list of acronyms in chapter 9 of the main document of the impact assessment is also valid for this document.
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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
### 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.

<table>
<thead>
<tr>
<th>Option 0</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Description</strong></td>
<td>Do nothing. This would maintain rules allowing priority dispatch and priority access for RES, indigenous fuels and CHP.</td>
<td>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.</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Pros</strong></td>
<td>Efficient use of resources, clearly distinguishes market-based use of capacities and potentially subsidy-based installation of capacities, making subsidies transparent.</td>
<td>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.</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Cons</strong></td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
</tr>
</tbody>
</table>

**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 sufficiently 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 ofremedying 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 "when 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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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 and the share of annual demand covered by wind power has risen from 19 % in 2009 to 42 % in 2015. Adding to this the share of 50.6 % of CHP in total Danish power generation, which makes Denmark one of the Member States with the highest share of CHP, 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. 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.

7 See: http://www.netztransparenz.de/de/Studie-konventionelle-Mindererzeugung.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.

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 resources to generate electricity at a time where other, cheaper, technologies were available;

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Priority dispatch rules for generation installations using indigenous resources 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. 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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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\(^\text{10}\), 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\(^\text{11}\), 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 resources should be used first, thus curtailing or redispaching first those generators which offer to do this against market-based compensation. In a second step, where no market-based resources 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 addressing 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. 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.

Figure 1: Reduction in system costs by abolishment of priority rules

<table>
<thead>
<tr>
<th></th>
<th>Baseline</th>
<th>Option 1a</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy (TWh)</td>
<td>3620</td>
<td>3610</td>
</tr>
<tr>
<td>CO2 emissions (Mt)</td>
<td>555</td>
<td>615</td>
</tr>
<tr>
<td>Cost day-ahead (B€)</td>
<td>82.5</td>
<td>76.9</td>
</tr>
<tr>
<td>Cost intraday (B€)</td>
<td>1.4</td>
<td>0.9</td>
</tr>
<tr>
<td>Cost balancing (B€)</td>
<td>-0.5</td>
<td>-0.3</td>
</tr>
<tr>
<td>Total cost (B€)</td>
<td>83.4</td>
<td>77.5</td>
</tr>
<tr>
<td>Savings (B€)</td>
<td>-</td>
<td>5.9</td>
</tr>
<tr>
<td>Load payment (B€)</td>
<td>278</td>
<td>293</td>
</tr>
<tr>
<td>Average price (€/MWh)</td>
<td>79</td>
<td>83</td>
</tr>
</tbody>
</table>

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.

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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.
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\textsuperscript{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

\textsuperscript{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\textsuperscript{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\textsuperscript{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


\textsuperscript{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 resources prior to any non-market based curtailment. Where balancing resources are available, including from RES E, and capable of addressing 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.\footnote{\url{http://www.eurobat.org/sites/default/files/eurobat_batteryenergystorage_web.pdf} p.28.}

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
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 address 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.
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.

<table>
<thead>
<tr>
<th>Description</th>
<th>Option 0</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Objective</strong></td>
<td>Do nothing. This would maintain the status quo, expressly requiring financial balancing responsibility only under the State aid guidelines which allow for some exceptions.</td>
<td>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.</td>
<td>Balancing responsibility with exemption possibilities for emerging technologies and/or small installations. This would build on the EEAG.</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Pros</strong></td>
<td>Lowest political resistance</td>
<td>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.</td>
<td>This could allow shielding emerging technologies or small installations from the technical and administrative effort and financial risk related to balancing responsibility.</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Cons</strong></td>
<td>Financial risks resulting from the operation of variable power generation (notably wind and solar power) are increased.</td>
<td>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).</td>
<td>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.</td>
<td></td>
</tr>
</tbody>
</table>

**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\(^\text{18}\). 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 subsidized renewable generation, thus shielding individual generators from imbalance risks of their power plants\(^\text{19}\) and collectively purchasing/selling balancing energy for the renewable sector\(^\text{20}\). 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)\(^\text{21}\).

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


\(^{19}\) \text{https://www.energy-community.org/portal/page/portal/ENC_HOME/DOCS/2014187/0633975ACF8E7B9CE053C92FA8C06338.PDF}

\(^{20}\) \text{http://www.oem-ag.at/de/oekostromneu/ausgleichsenergie/}

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 weather 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. Part of this challenge is the need to avoid unacceptable risks for RES E investors by imposing balance responsibilities without

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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\textsuperscript{23}. Whereas many Member States already foresee some balancing responsibility for RES E generators (2013: 16 Member States)\textsuperscript{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\textsuperscript{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".

Reference is also made to Section 7.4.2 of the evaluation.

1.2.4. Presentation of the options

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

\textsuperscript{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 incentivised by balancing arrangements."
\textsuperscript{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 weather 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 weather 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.
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. **Subsidiarity**

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 responsibility 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 submitted26 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

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 addressed 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
### Objective: transparent, non-discriminatory and market based framework for non-frequency ancillary services

<table>
<thead>
<tr>
<th>Option 0</th>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>BAU</strong></td>
<td>Description</td>
<td>Description</td>
</tr>
<tr>
<td>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.</td>
<td>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.</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Stronger enforcement</strong></td>
<td>Pro</td>
<td>Pro</td>
</tr>
<tr>
<td>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.</td>
<td>Accelerate adoption in Member States of provisions that facilitate the participation of RES to ancillary services as technical capabilities of RES 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.</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Con</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>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 is connected.</td>
<td></td>
<td>Possibility of uneven regulatory and therefore market developments depending on how fast Member States act. This creates uncertain prospects for businesses slowing down RES penetration.</td>
</tr>
</tbody>
</table>

**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 developed 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 ancillary 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 Commission27, a survey commissioned by ENTSO-E28 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.

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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
Currently the practises with regard to requirements, procurement and remuneration of non-frequency auxiliary 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 auxiliary services. However, there is nothing specific with regard to non-frequency auxiliary 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
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) 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 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 ancillary services have to be provided on a local level, the provision of and revenues from these services can

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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 outweighed the costs already at System Non-Synchronous Penetration levels below 50%.

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 ancillary 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


RES E access to provision of non-frequency ancillary services
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\textsuperscript{32} and demand response\textsuperscript{33} industry associations and owners of storage\textsuperscript{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 Manufacturer 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. Ancillary services should thus be compensated\textsuperscript{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"\textsuperscript{36}.

\textsuperscript{34} "Technical and regulatory aspects of the provision of ancillary services by battery storage" (2015) Younicos
\textsuperscript{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”.  

2. Detailed measures assessed under Problem Area I, option 1(b)

Strengthening short-term markets
RES E access to provision of non-frequency ancillary services
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

<table>
<thead>
<tr>
<th>Description</th>
<th>Option 0: business as usual</th>
<th>Option 1: national sizing and procurement of balancing reserves on daily basis</th>
<th>Option 2: regional sizing and procurement of balancing reserves</th>
<th>Option 3: European sizing and procurement of balancing reserves</th>
</tr>
</thead>
<tbody>
<tr>
<td>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.</td>
<td>This option consists in developing a binding regulation that would require TSOs to size their balancing reserves on daily probabilistic methodologies. Daily calculation allows procuring lower balancing reserves and, together with daily procurement, enables participation of renewable energy sources and demand response. This option foresees 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.</td>
<td>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.</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>Pros</td>
<td>Pro – optimal national sizing and procurement of balancing reserves</td>
<td>Pro – regional areas for sizing and procurement of balancing reserves</td>
<td>Pro – single European balancing zone</td>
<td></td>
</tr>
<tr>
<td>Cons</td>
<td>Con – no cross-border optimisation of balancing reserves</td>
<td>Con – balancing zones still based on national borders but cross-border optimisation possible</td>
<td>Con – extensive standardisation through replacement of national systems, difficult and costly implementation</td>
<td></td>
</tr>
</tbody>
</table>

**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. 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 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.

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

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
decades which is mainly due to large-scale cross-border flows and high volumes of variable RES 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) 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

In their Market Monitoring report 2014, 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 emphasises the importance of optimising the procurement costs of balancing capacity, including separate procurement of upward and downward balancing capacity and shorter procurement timeframes.

Source: Belgian TSO report on the evolution of ancillary services needs to balance the Belgian control areas towards 2018, pp. 32)

41 Belgian TSO report on the evolution of ancillary services need to balance the Belgian control area towards 2018, May 2013

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)

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 (%)

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

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 exchanging 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

<table>
<thead>
<tr>
<th></th>
<th>BAU</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balancing reserves needs (GW)</td>
<td>53.4</td>
<td>52.1</td>
<td>29.9</td>
<td>17.1</td>
</tr>
<tr>
<td>Balancing reserves needs reduction</td>
<td>-</td>
<td>3%</td>
<td>44%</td>
<td>68%</td>
</tr>
<tr>
<td>Annual savings (EUR billion)</td>
<td>-</td>
<td>1.8</td>
<td>3.4</td>
<td>4.5</td>
</tr>
</tbody>
</table>

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 platforms 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 agreement 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 particular, 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."
Reserves sizing and procurement
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.

<table>
<thead>
<tr>
<th></th>
<th>Option 0</th>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
</table>
| **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 voluntary 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(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."

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.

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44 Ofgem, [https://www.ofgem.gov.uk/electricity/wholesale-market/liquidity](https://www.ofgem.gov.uk/electricity/wholesale-market/liquidity)
Figure 1 – ID traded volumes in selection of EU markets – 2011-2014 (TWh).


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%.

<table>
<thead>
<tr>
<th>Country</th>
<th>Ratio (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ES</td>
<td>12.1</td>
</tr>
<tr>
<td>IT</td>
<td>7.4</td>
</tr>
<tr>
<td>PT</td>
<td>7.6</td>
</tr>
<tr>
<td>DE</td>
<td>4.6</td>
</tr>
<tr>
<td>GB</td>
<td>4.4</td>
</tr>
<tr>
<td>SI</td>
<td>1.0</td>
</tr>
<tr>
<td>BE</td>
<td>1.0</td>
</tr>
<tr>
<td>SE</td>
<td>1.0</td>
</tr>
<tr>
<td>LT</td>
<td>1.0</td>
</tr>
<tr>
<td>FR</td>
<td>0.7</td>
</tr>
<tr>
<td>CZ</td>
<td>0.7</td>
</tr>
<tr>
<td>NL</td>
<td>0.2</td>
</tr>
<tr>
<td>PL</td>
<td>0.1</td>
</tr>
</tbody>
</table>

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.
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. Presentation of the options

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 harmonisation 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 legislation 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

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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 Germany47, it was found that, whilst the auction pulled some value away from the continuous intraday market, the total traded volumes increased.

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 liquidity 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 properly integrated, 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

48 "A market design fit for renewables". Wind Europe submission of 27 June 2016
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."

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\(^{52}\) 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**

<table>
<thead>
<tr>
<th>Description</th>
<th>Option 0</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>BAU</strong></td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Pros</strong></td>
<td>Lowest political resistance.</td>
<td>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 decision-making with a possibility to entrust ROCs with decision making competences on a number of issues.</td>
<td>Improved system and market operation leading to optimal results including optimized infrastructure development, market facilitation and use of existing infrastructure, secure real time operation.</td>
<td>Seamless and efficient system and market operation.</td>
</tr>
<tr>
<td><strong>Cons</strong></td>
<td>Suboptimal in the medium and long-term.</td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
</tr>
</tbody>
</table>

**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

![Electricity Value Chain Diagram]

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.

Coordination of transmission system operation: shift from a voluntary approach to a mandatory framework

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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.
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

<table>
<thead>
<tr>
<th><strong>Common grid model</strong>: 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).</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Operational planning security analysis</strong>: 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.</td>
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<tr>
<td><strong>Coordinated capacity calculation</strong>: 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.</td>
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<tr>
<td><strong>Short and very short-term adequacy forecasts</strong>: 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).</td>
</tr>
<tr>
<td><strong>Outage planning coordination</strong>: 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).</td>
</tr>
<tr>
<td><strong>Consistency assessment of the TSOs' system defence plans and restoration plans</strong>: RSCs will assist TSOs in ensuring the consistency of the system defence plans and restoration plan.</td>
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</table>

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 retain 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 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.

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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 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, 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 subsequently 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.

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
structual 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 activities. 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

<table>
<thead>
<tr>
<th></th>
<th>RSCs (Option 0)</th>
<th>ROCs (Option 1)</th>
<th>RISOs/EU ISO (Options 2 and 3)</th>
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<tbody>
<tr>
<td><strong>System Operation</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coordinated Security Analysis</td>
<td>x</td>
<td>x \textsuperscript{56}</td>
<td>x</td>
</tr>
<tr>
<td>(including Remedial Actions-</td>
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<td></td>
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<tr>
<td>related analysis)</td>
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<tr>
<td>Common Grid Model Delivery</td>
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<td>x</td>
<td>x</td>
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<tr>
<td>Outage Planning Coordination</td>
<td>x</td>
<td>x</td>
<td>x</td>
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<tr>
<td>Short and Medium Term Resource</td>
<td>x</td>
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<td>x</td>
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<tr>
<td>Adequacy Forecasts</td>
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<td>Regional system defence and</td>
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<td>restoration plans</td>
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<td>Centralised post operation</td>
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<tr>
<td>analyses and reporting</td>
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<tr>
<td>Training and certification</td>
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<tr>
<td><strong>Market Related</strong></td>
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<tr>
<td>Coordinated Capacity Calculation</td>
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<td>x \textsuperscript{57}</td>
<td>x \textsuperscript{58}</td>
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<tr>
<td>Coordinated sizing and</td>
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<tr>
<td>procurement of balancing reserves</td>
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<tr>
<td><strong>Network Planning</strong></td>
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<td>Identification of the</td>
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<tr>
<td>transmission capacity needs</td>
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<tr>
<td>Technical and economic</td>
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<tr>
<td>assessment of CBCA cases</td>
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<tr>
<td>Administration of TSO-TSO</td>
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<td>compensation mechanisms (ITC,</td>
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<td>congestion rent sharing,</td>
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<td>redispatching cost sharing,</td>
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<tr>
<td>CBCA)</td>
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<tr>
<td><strong>Risk-preparedness</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Support Member States on</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>development of risk preparedness plans</td>
<td>x</td>
<td>x</td>
<td></td>
</tr>
</tbody>
</table>

*Source: DG ENER*

\textsuperscript{56} It could include decision-making powers.

\textsuperscript{57} The CACM Guideline provides for regional capacity calculators. However, following the commitments of ENTSO-E, this role could be already assumed for RSCs.

\textsuperscript{58} It could include decision-making powers.
Table 2 Qualitative estimate of the economic impact of the Options:

<table>
<thead>
<tr>
<th>Economic Impact</th>
<th>Option 0: RSC approach</th>
<th>Option 1: ROC approach</th>
<th>Option 2: RISO approach</th>
<th>Option 3: EU ISO approach</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enhancing security of supply by minimising the risk of blackouts(^59)(^60)</td>
<td>0/+</td>
<td>+</td>
<td>++</td>
<td>++</td>
</tr>
<tr>
<td>Lowering costs through increased efficiency in system operation(^61)(^62)(^63)</td>
<td>0/+</td>
<td>++</td>
<td>+++</td>
<td>+++</td>
</tr>
<tr>
<td>Maximising transmission capacity offered to the market(^64)</td>
<td>0/+</td>
<td>++</td>
<td>+++</td>
<td>+++</td>
</tr>
</tbody>
</table>

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.


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.
Improving the coordination of Transmission System Operation

| Reducing the need of remedial actions by coordinating and activating in a coordinated way redispatching | 0/+ | ++ | +++ | +++ |
| Minimising the costs of balancing provision by taking a more coordinated approach towards the sizing of balancing reserves | 0/+ | ++ | +++ | +++ |
| Optimisation of infrastructure planning | 0 | 0 | ++ | +++ |

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).


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.


According to the study carried out by Artylys 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.

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.
Improving the coordination of Transmission System Operation

<table>
<thead>
<tr>
<th>Enhancing transparency</th>
<th>0</th>
<th>0/+</th>
<th>+</th>
<th>+</th>
</tr>
</thead>
<tbody>
<tr>
<td>Costs of implementation</td>
<td>0/-</td>
<td>-</td>
<td>---</td>
<td>----</td>
</tr>
<tr>
<td>Other impacts</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Administrative impacts/governance</td>
<td>0/-</td>
<td>-</td>
<td>--</td>
<td>---</td>
</tr>
</tbody>
</table>

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 RSCIIs 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). 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. 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 coordinators 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. 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. 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. 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).

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Option 0: BAU</th>
<th>Option 1: ROC approach</th>
<th>Option 2: RISO approach</th>
<th>Option 3: EU ISO approach</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quality</td>
<td>0/+</td>
<td>++</td>
<td>+++</td>
<td>+++</td>
</tr>
<tr>
<td></td>
<td>Progress remains limited due to zones not based on technical operation of the grid</td>
<td>More efficient as optimisation over zones based on technical operation of the grid</td>
<td>Very efficient because of enhanced system operation at regional level</td>
<td>Most efficient because of seamless system operation at EU level</td>
</tr>
<tr>
<td>Speed of implementation</td>
<td>+</td>
<td>0</td>
<td>Can partially build upon established structures but it will require a substantial centralization at regional level; change in geographical scope of functions; it would require a substantial amount of time for implementation.</td>
<td>Can partially build upon established structures; change in geographical scope and functions</td>
</tr>
<tr>
<td>Use of established institutional processes</td>
<td>++</td>
<td>-</td>
<td>Requires building up new structures/processes (possibly some decision-making responsibility)</td>
<td>--</td>
</tr>
<tr>
<td>Secure operation of the network</td>
<td>0/+</td>
<td>+</td>
<td>Enhanced cooperation via ROCs; reduced risk of blackout</td>
<td>++</td>
</tr>
<tr>
<td>Efficient organisational structure</td>
<td>-</td>
<td>++</td>
<td>Efficient organisational structure can be created; services for a region carried out by one company</td>
<td>+++</td>
</tr>
<tr>
<td>Political sensitivity</td>
<td>0</td>
<td>-</td>
<td>Politically sensitive due to shift in decision-making responsibility for relevant functions</td>
<td>--</td>
</tr>
</tbody>
</table>
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. 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.

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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 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 transition towards a truly integrated and decarbonised electricity market will be more efficient if the electricity system is optimised on a regional 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".
2.3.6. Subsidiarity

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. Stakeholders’ opinions

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 diverging opinions as regards the delineation of responsibilities between regional centres and national TSOs and that further consideration was needed.

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.

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Improving the coordination of Transmission System Operation
Improving the coordination of Transmission System Operation
3. Detailed measures assessed under Problem Area I, option 1(c); pulling demand response and distributed resources into the market
Improving the coordination of Transmission System Operation
3.1. Unlocking demand side response
### 3.1.1. Summary table

<table>
<thead>
<tr>
<th>Objective: Unlock the full potential of demand response</th>
<th>Option O: BAU</th>
<th>Option 1: Give consumers access to technologies that allow them to participate in price based demand response schemes</th>
<th>Option 2: as Option 1 but also fully enable incentive based demand response</th>
<th>Option 3: mandatory smart meter roll out and full EU framework for incentive based demand response</th>
</tr>
</thead>
<tbody>
<tr>
<td>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</td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>No new legislative intervention.</td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>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.</td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>Most suitable option(s): Option 2.</td>
<td>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.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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, for example by providing energy management services, developing innovative pricing formulas, or introducing intelligent metering systems or smart grids, where appropriate.".

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\(^{82}\) 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 systems83. It aimed at guiding Member States in their choices, drawing particular attention to: (i) key functionalities for fit-for-purpose and pro-consumer arrangements84; (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 Directive85.

Smart Metering Deployment in Member States

According to data from the Commission Report "Benchmarking smart metering deployment in the EU-27", as also recently updated86, 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 electricity87. 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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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)
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. 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 – 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 interworking 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, 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")

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

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.
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 procurement92.

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 side resources and 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


Unlocking demand side response
(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 demand 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
Unlocking demand side response balancing and ancillary services markets. In the UK, the market for ancillary services 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>
<thead>
<tr>
<th>Member State</th>
<th>Demand Side Products (DSP) in energy markets</th>
<th>DSP in balancing markets</th>
<th>DSP in capacity mechanisms</th>
<th>Estimated demand response for 2016 (in GW)</th>
</tr>
</thead>
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<tr>
<td>Austria</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>104</td>
</tr>
<tr>
<td>Belgium</td>
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<td>Yes</td>
<td>Yes</td>
<td>689</td>
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<td></td>
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<td>No market</td>
<td></td>
<td>0</td>
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<td>Yes</td>
<td>Yes</td>
<td>1792</td>
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<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>15628</strong></td>
</tr>
</tbody>
</table>

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

Implicit (price based) demand response

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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,**

[Graph showing type of energy pricing]


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\textsuperscript{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**

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{demand_response_potential.png}
\caption{Theoretical demand response potential 2030}
\end{figure}

*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")

\textsuperscript{94} "Impact Assessment support Study on downstream flexibility, demand response and smart metering", (2016) COWI
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\(^\text{95}\) 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,

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\(^\text{95}\) Commission Recommendation on preparations for the roll-out of smart metering systems (2012)  

Unlocking demand side response
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.\textsuperscript{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.\textsuperscript{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\textsuperscript{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

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\textsuperscript{97} Commission Staff Working Document "Cost-benefit analyses & state of play of smart metering deployment in the EU-27" (2014) Table 8
\textsuperscript{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
\textsuperscript{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
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 6000 kWh is proposed;
- In Slovakia, the CBA considers that consumers with annual consumption above 4000 kWh (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**

<table>
<thead>
<tr>
<th></th>
<th>BAU = Option 0</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2016</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Smart meter</td>
<td>35%</td>
<td>35%</td>
<td>35%</td>
<td>35%</td>
</tr>
<tr>
<td><strong>2020</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Smart meter</td>
<td>71%</td>
<td>72%</td>
<td>72%</td>
<td>72%</td>
</tr>
<tr>
<td><strong>2030</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Smart meter</td>
<td>74%</td>
<td>81%</td>
<td>81%</td>
<td>90%</td>
</tr>
</tbody>
</table>

*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:\footnote{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

<table>
<thead>
<tr>
<th></th>
<th>BAU</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016 ToU</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>Dynamic</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>2020 ToU</td>
<td>18%</td>
<td>18%</td>
<td>18%</td>
<td>18%</td>
</tr>
<tr>
<td>Dynamic</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
</tr>
<tr>
<td>2030 ToU</td>
<td>26%</td>
<td>26%</td>
<td>26%</td>
<td>26%</td>
</tr>
<tr>
<td>Dynamic</td>
<td>16%</td>
<td>16%</td>
<td>16%</td>
<td>16%</td>
</tr>
</tbody>
</table>

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 smart 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%.

**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.

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

<table>
<thead>
<tr>
<th>Year</th>
<th>BAU</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Price-based</td>
<td>5.8</td>
<td>5.8</td>
<td>5.8</td>
<td>5.8</td>
</tr>
<tr>
<td>Incentive-based</td>
<td>15.6</td>
<td>15.6</td>
<td>15.6</td>
<td>15.6</td>
</tr>
<tr>
<td>Total</td>
<td>21.4</td>
<td>21.4</td>
<td>21.4</td>
<td>21.4</td>
</tr>
<tr>
<td>2020</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Price-based</td>
<td>6.4</td>
<td>6.9</td>
<td>6.9</td>
<td>6.9</td>
</tr>
<tr>
<td>Incentive-based</td>
<td>16.3</td>
<td>16.3</td>
<td>20.3</td>
<td>21.4</td>
</tr>
<tr>
<td>Total</td>
<td>22.7</td>
<td>23.3</td>
<td>27.2</td>
<td>28.4</td>
</tr>
<tr>
<td>2030</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Price-based</td>
<td>15.4</td>
<td>17.9</td>
<td>17.9</td>
<td>17.9</td>
</tr>
<tr>
<td>Incentive-based</td>
<td>19.0</td>
<td>19.0</td>
<td>34.6</td>
<td>39.3</td>
</tr>
<tr>
<td>Total</td>
<td>34.4</td>
<td>36.8</td>
<td>52.4</td>
<td>57.1</td>
</tr>
</tbody>
</table>

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. Available data there coming from the CBAs 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;

104 idem
Unlocking demand side response

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; 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 CO₂ 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. 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.

---

\[^{107}\] 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

<table>
<thead>
<tr>
<th>Country</th>
<th>Metering points</th>
<th>Smart meter penetration rate by 2030</th>
<th>Additional meters by 2030 (compared to BAU)</th>
<th>Indicative cost (EUR million) by 2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>5,700,000</td>
<td>95%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Belgium</td>
<td>5,975,000</td>
<td>0%</td>
<td>40%</td>
<td>667</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>4,000,000</td>
<td>0%</td>
<td>40%</td>
<td>446</td>
</tr>
<tr>
<td>Croatia</td>
<td>2,500,000</td>
<td>0%</td>
<td>40%</td>
<td>279</td>
</tr>
<tr>
<td>Cyprus</td>
<td>450,000</td>
<td>0%</td>
<td>40%</td>
<td>50</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>5,700,000</td>
<td>0%</td>
<td>40%</td>
<td>636</td>
</tr>
<tr>
<td>Denmark</td>
<td>3,280,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Estonia</td>
<td>709,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Finland</td>
<td>3,300,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>France</td>
<td>35,000,000</td>
<td>95%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Germany</td>
<td>47,900,000</td>
<td>31%</td>
<td>10%</td>
<td>1,270</td>
</tr>
<tr>
<td>Greece</td>
<td>7,000,000</td>
<td>80%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Hungary</td>
<td>4,063,366</td>
<td>0%</td>
<td>40%</td>
<td>453</td>
</tr>
<tr>
<td>Ireland</td>
<td>2,200,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Italy</td>
<td>36,700,000</td>
<td>99%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Latvia</td>
<td>1,089,109</td>
<td>95%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Lithuania</td>
<td>1,600,000</td>
<td>0%</td>
<td>40%</td>
<td>179</td>
</tr>
<tr>
<td>Luxembourg</td>
<td>260,000</td>
<td>95%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Malta</td>
<td>260,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Netherlands</td>
<td>7,600,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Poland</td>
<td>16,500,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Portugal</td>
<td>6,500,000</td>
<td>0%</td>
<td>40%</td>
<td>725</td>
</tr>
<tr>
<td>Romania</td>
<td>9,000,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Slovakia</td>
<td>2,625,000</td>
<td>23%</td>
<td>17%</td>
<td>125</td>
</tr>
<tr>
<td>Slovenia</td>
<td>1,000,000</td>
<td>0%</td>
<td>40%</td>
<td>112</td>
</tr>
<tr>
<td>Spain</td>
<td>27,768,258</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Sweden</td>
<td>5,200,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>UK</td>
<td>32,940,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>276,819,733</strong></td>
<td><strong>74%</strong></td>
<td><strong>7%</strong></td>
<td><strong>4,942</strong></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Country</th>
<th>Metering points</th>
<th>Smart meter penetration rate by 2030</th>
<th>Additional meters by 2030 (compared to BAU)</th>
<th>Indicative cost (EUR million) by 2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>5,700,000</td>
<td>95%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Belgium</td>
<td>5,975,000</td>
<td>0%</td>
<td>80%</td>
<td>1334</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>4,000,000</td>
<td>0%</td>
<td>80%</td>
<td>893</td>
</tr>
<tr>
<td>Croatia</td>
<td>2,500,000</td>
<td>0%</td>
<td>80%</td>
<td>558</td>
</tr>
<tr>
<td>Cyprus</td>
<td>450,000</td>
<td>0%</td>
<td>80%</td>
<td>100</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>5,700,000</td>
<td>0%</td>
<td>80%</td>
<td>1272</td>
</tr>
<tr>
<td>Denmark</td>
<td>3,280,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Estonia</td>
<td>709,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Finland</td>
<td>3,300,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>France</td>
<td>35,000,000</td>
<td>95%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Germany</td>
<td>47,900,000</td>
<td>31%</td>
<td>49%</td>
<td>6,615</td>
</tr>
<tr>
<td>Greece</td>
<td>7,000,000</td>
<td>80%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Hungary</td>
<td>4,063,366</td>
<td>0%</td>
<td>80%</td>
<td>907</td>
</tr>
<tr>
<td>Ireland</td>
<td>2,200,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Italy</td>
<td>36,700,000</td>
<td>99%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Latvia</td>
<td>1,089,109</td>
<td>95%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Lithuania</td>
<td>1,600,000</td>
<td>0%</td>
<td>80%</td>
<td>357</td>
</tr>
<tr>
<td>Luxembourg</td>
<td>260,000</td>
<td>95%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Malta</td>
<td>260,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Netherlands</td>
<td>7,600,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Poland</td>
<td>16,500,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Portugal</td>
<td>6,500,000</td>
<td>0%</td>
<td>80%</td>
<td>1451</td>
</tr>
<tr>
<td>Romania</td>
<td>9,000,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Slovakia</td>
<td>2,625,000</td>
<td>23%</td>
<td>57%</td>
<td>417</td>
</tr>
<tr>
<td>Slovenia</td>
<td>1,000,000</td>
<td>0%</td>
<td>80%</td>
<td>223</td>
</tr>
<tr>
<td>Spain</td>
<td>27,768,258</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Sweden</td>
<td>5,200,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>UK</td>
<td>32,940,000</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>276,819,733</strong></td>
<td><strong>74%</strong></td>
<td><strong>16%</strong></td>
<td><strong>14,127</strong></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th></th>
<th>BAU = Option 0</th>
<th>Option 1, Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>2030</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Smart meter (penetration rate)</td>
<td>74%</td>
<td>81%</td>
<td>90%</td>
</tr>
<tr>
<td>Additional 'net' cost (considering 15 years, at 3.5%)</td>
<td>EUR 215 million/year</td>
<td>EUR 613 million/year</td>
<td></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Cost component</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Variable costs</td>
<td>Costs for loss of production, inconvenience costs, storage losses</td>
<td>EUR/kWh</td>
</tr>
<tr>
<td>Annual fixed costs</td>
<td>Information costs, transaction costs, control costs</td>
<td>EUR/kW</td>
</tr>
<tr>
<td>Investment costs</td>
<td>Installation of measurement-equipment, automatic measurement for control, communication equipment</td>
<td>EUR/kW</td>
</tr>
</tbody>
</table>

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\(^\text{113}\) 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

<table>
<thead>
<tr>
<th>Option</th>
<th>BAU</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total demand response potential 2030 (GW)</td>
<td>34.4</td>
<td>36.8</td>
<td>52.4</td>
<td>57.1</td>
</tr>
<tr>
<td>Total Value demand response (million EUR/y)</td>
<td>3517</td>
<td>3772</td>
<td>4588</td>
<td>4736</td>
</tr>
</tbody>
</table>

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

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\(^{113}\) 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**

<table>
<thead>
<tr>
<th></th>
<th>BAU</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total peak decrease 2030 (GW)</td>
<td>25.8</td>
<td>28.1</td>
<td>36.4</td>
<td>38.0</td>
</tr>
<tr>
<td>Total benefit demand response in distribution and transmission grid (million EUR/y)</td>
<td>980</td>
<td>1068</td>
<td>1383</td>
<td>1444</td>
</tr>
</tbody>
</table>

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)**

<table>
<thead>
<tr>
<th></th>
<th>BAU</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Costs</td>
<td>82</td>
<td>303</td>
<td>322</td>
<td>328</td>
</tr>
<tr>
<td>Benefits</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Network</td>
<td>980</td>
<td>1068</td>
<td>1383</td>
<td>1444</td>
</tr>
<tr>
<td>Generation</td>
<td>3517</td>
<td>3772</td>
<td>4588</td>
<td>4736</td>
</tr>
<tr>
<td>Total</td>
<td>4497</td>
<td>4840</td>
<td>5971</td>
<td>6180</td>
</tr>
<tr>
<td>Net benefit</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(compared to no demand response)</td>
<td>4415</td>
<td>4537</td>
<td>5649</td>
<td>5852</td>
</tr>
<tr>
<td>Net benefit</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(compared to BAU)</td>
<td>122</td>
<td>1234</td>
<td>1437</td>
<td></td>
</tr>
</tbody>
</table>

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 1, 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.

**CO₂ emission reductions**

Next to the monetary impact also CO₂ 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>
<thead>
<tr>
<th>Reduction in CO₂ emissions in Mton/y</th>
<th>BAU</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduction in CO₂ emissions in Mton/y</td>
<td>12.4</td>
<td>13.0</td>
<td>12.7</td>
<td>12.4114</td>
</tr>
</tbody>
</table>

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.

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114 For options 2 and 3 the CO₂ 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.

c. 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
Unlocking demand side response

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
Unlocking demand side response

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
Unlocking demand side response 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.

**Option 1**

- 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 roll out 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 pricing 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.

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."
Unlocking demand side response


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 think 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.


"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."


- "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
Unlocking demand side response
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 regulators119 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 discussing121 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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120 idem


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”125.

**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 requirements126 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”;


124 ENTSO-E policy paper "Market design for demand response", November 2015;  

125 ENTSO-E position paper "Towards smarter grids: Developing TSO and DSO roles and interactions for the benefit of consumers", March 2015;  

126 ENTSO-E policy paper "Market design for demand response", November 2015;  
(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".

**DSOs (CEDEC, EDSO for Smart Grids, EURELECTRIC, GEODE)**

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 "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 "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". Such settings are more complex and in fact "only possible with a smart meter".

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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.


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". 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. 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".

Furthermore, EDSO states that "DSOs could make the most of their grid provided that they are allowed to use system flexibility services". 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 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

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.
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". As Eurelectric explains, 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". 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".

To untap the full demand response potential, Eurelectric recommends:

(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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139 Idem


Unlocking demand side response

(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". 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 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
facilitate more advanced dynamic pricing and new demand response services.\textsuperscript{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\textsuperscript{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\textsuperscript{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

\textsuperscript{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


\textsuperscript{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
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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 technologies¹⁴⁸ 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

¹⁴⁸ E.g. smart meters, varying user interfaces, smart appliances and home automation

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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*". In fact to *guarantee consumers can benefit from demand response*, BEUC sees that

(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](http://eusew.eu/engaged-customers-driving-energy-transition)

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.

<table>
<thead>
<tr>
<th>Objective: Enable Distribution System Operators (‘DSOs’) to locally manage challenges of energy transition in a cost-efficient and sustainable way, without distorting the market.</th>
<th>Option: 0</th>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU</td>
<td>- Allow and incentivize DSOs to acquire flexibility services from distributed energy resources.</td>
<td>- Allow DSOs to use flexibility under the conditions set in Option 1.</td>
<td></td>
</tr>
<tr>
<td>Member States are primarily responsible on deciding on the detail tasks of DSOs.</td>
<td>- Establish specific conditions under which DSOs should use flexibility, and ensure the neutrality of DSOs when interacting with the market or consumers.</td>
<td>- Define specific set of tasks (allowed and not allowed) for DSOs across EU.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- 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.</td>
<td>- Enforce existing unbundling rules also to DSOs with less than 100,000 customers (small DSOs).</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Establish cooperation between DSOs and TSOs on specific areas, alongside the creation of a single European DSO entity.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pro</td>
<td>Current framework gives more flexibility to Member States to accommodate local conditions in their national measures.</td>
<td>Pro</td>
<td>Pro</td>
</tr>
<tr>
<td></td>
<td>Use of flexible resources by DSOs will support integration of RES E in distribution grids in a cost-efficient way.</td>
<td>Use of flexible resources by DSOs will support integration of RES E in distribution grids in a cost-efficient way.</td>
<td>Stricter unbundling rules would possibly enhance competition in distribution systems which are currently exempted from unbundling requirements.</td>
</tr>
<tr>
<td></td>
<td>Measures which ensure neutrality of DSOs and will guarantee that operators do not take advantage of their monopolistic position in the market.</td>
<td>Measures which ensure neutrality of DSOs and will guarantee that operators do not take advantage of their monopolistic position in the market.</td>
<td>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.</td>
</tr>
<tr>
<td>Con</td>
<td>Not all Member States are integrating required changes in order to support EU internal energy market and targets.</td>
<td>Con</td>
<td>Con</td>
</tr>
<tr>
<td></td>
<td>Effectiveness of measures may still depend on remuneration of DSOs and regulatory framework at national level.</td>
<td>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.</td>
<td></td>
</tr>
</tbody>
</table>

**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 sets 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 CEER153 (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

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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**

![Figure 1: Number of electricity DSOs per Member State](image)

*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\textsuperscript{154}.

In meeting the 2020 targets and 2030 climate and energy objectives\textsuperscript{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\textsuperscript{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\textsuperscript{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.

\textsuperscript{154} "Study on tariff design for distribution systems" (2015) AF Mercados, refE, Indra.
\textsuperscript{155} COM(2014) 15 final "A policy framework for climate and energy in the period from 2020 to 2030".
\textsuperscript{156} EvolvDSO project (Deliverable 1.1) and other sources.
\textsuperscript{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.
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)

<table>
<thead>
<tr>
<th>Country</th>
<th>2014</th>
<th>2030 (projected)</th>
<th>Annual expected increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portugal</td>
<td>743</td>
<td>867,000</td>
<td>55%</td>
</tr>
<tr>
<td>Denmark</td>
<td>2,799</td>
<td>436,000</td>
<td>37%</td>
</tr>
<tr>
<td>Spain</td>
<td>3,536</td>
<td>4,263,000</td>
<td>56%</td>
</tr>
<tr>
<td>Sweden</td>
<td>6,990</td>
<td>517,000</td>
<td>31%</td>
</tr>
<tr>
<td>Italy</td>
<td>7,584</td>
<td>6,638,000</td>
<td>53%</td>
</tr>
<tr>
<td>UK</td>
<td>21,425</td>
<td>3,735,000</td>
<td>38%</td>
</tr>
<tr>
<td>Germany</td>
<td>24,419</td>
<td>10,024,000</td>
<td>46%</td>
</tr>
<tr>
<td>France</td>
<td>30,912</td>
<td>5,431,000</td>
<td>38%</td>
</tr>
<tr>
<td>Norway</td>
<td>40,887</td>
<td>429,000</td>
<td>16%</td>
</tr>
<tr>
<td>Netherlands</td>
<td>43,762</td>
<td>982,000</td>
<td>21%</td>
</tr>
</tbody>
</table>

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.

\(^{158}\) 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

<table>
<thead>
<tr>
<th>Procurement of flexibility services</th>
<th>Number of Member States</th>
<th>Member state</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSOs cannot contract flexibility services</td>
<td>8</td>
<td>FI, FR, IE, IT, PT, EL, NL, ES</td>
</tr>
<tr>
<td>DSOs can contract system flexibility services for constraints management in certain situations</td>
<td>3</td>
<td>UK, BE, DE</td>
</tr>
</tbody>
</table>

Source: Copenhagen Economics, VVA Europe (2016).

According to EvolvDSO project\(^\text{161}\) 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.

\(^{161}\) 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.evolvdsos.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\(^\text{162}\). 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

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 Annex 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)\(^{163}\).

\(\text{b. Their respective key economic impacts and benefit/cost ratio, cost-effectiveness (efficiency) & Economic impacts}\)

\(\text{\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_}\)

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\(^{163}\) 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\(^\text{164}\) 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)\(^\text{165}\) 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>
<thead>
<tr>
<th>Table 3: Avoided grid investments from flexibility</th>
</tr>
</thead>
<tbody>
<tr>
<td>Extra grid investment from increased DG and load growth (EUR billion) yearly at EU level</td>
</tr>
<tr>
<td>Savings from demand flexibility alone (percent)</td>
</tr>
<tr>
<td>Savings from supply flexibility alone (percent)</td>
</tr>
<tr>
<td>Savings from combination of demand and supply flexibility (percentage)</td>
</tr>
<tr>
<td><strong>Very conservative estimate of avoided extra grid investments from flexibility yearly at EU level (EUR billion)</strong></td>
</tr>
</tbody>
</table>

Source: Copenhagen Economics, VVA Europe (2016).

McKinsey & Company (2015)\(^\text{166}\) 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.

\(^{164}\) "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.

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 the respondents view active distribution system operation, neutral market facilitation and

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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.

IFIIEC 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, 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."

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 | - 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. | Fully harmonize remuneration methodologies for all DSOs at EU level. |
| | - 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. | |
| Pro | Member States (NRAs) are mainly responsible on deciding on the detailed framework for the remuneration of DSOs. | Pro |
| | Current framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures. | 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. |
| 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. | 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

<table>
<thead>
<tr>
<th>Objective: Distribution tariffs that send accurate price signals to grid users and aim to fair allocation of distribution network costs.</th>
<th>Option: O</th>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU</td>
<td></td>
<td>- Impose on NRAs more detailed transparency and comparability requirements for distribution tariffs methodologies.</td>
<td>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.</td>
</tr>
<tr>
<td></td>
<td>Member States (NRAs) are mainly responsible for deciding on the detailed distribution tariffs.</td>
<td>- 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.</td>
<td>Pro</td>
</tr>
<tr>
<td>Pro</td>
<td>Current framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.</td>
<td>Principals regarding network tariffs will increase efficient use of the system and ensure a fairer allocation of network costs.</td>
<td>A harmonized methodology would guarantee the implementation of specific principles.</td>
</tr>
<tr>
<td>Con</td>
<td>Current EU framework provides only some general principles, and not specific guidance towards distribution network tariffs which effectively allocate costs and accommodate EU policies.</td>
<td>Detailed implementation will still have to be realized at Member State level, which may reduce effectiveness of measures in some cases.</td>
<td>Con</td>
</tr>
<tr>
<td>Most suitable option(s):</td>
<td></td>
<td>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.</td>
<td>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.</td>
</tr>
</tbody>
</table>

172 Distribution network tariffs and DSO remuneration
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, 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.

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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

<table>
<thead>
<tr>
<th>Tariff structure elements</th>
<th>Tariff component for household consumers</th>
<th>Tariff component for small industrial consumers</th>
<th>Tariff component for large industrial consumers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Member states where the volumetric element weights over 50% of the DSO tariff</td>
<td>AT, CY, CZ, FR, DE, GR, HU, IT, LU, PL, PT, RO, SK, SI, GB</td>
<td>CY, CZ, FI, FR, DE, GR, HU, RO, SE, SK, GB</td>
<td>AT, CY, FI, FR, GR, HU, PL, RO, SE, SK, SI, NL, GB</td>
</tr>
<tr>
<td>Member states where the capacity element + fixed charge weights over 50% of the DSO tariff</td>
<td>ES, SE, NL</td>
<td>AT, IT, LU, PL, PT, SI, ES, NL</td>
<td>CZ, DE, IT, LU, PT, ES</td>
</tr>
<tr>
<td>EU capacity element + fixed component average</td>
<td>31%</td>
<td>46%</td>
<td>42%</td>
</tr>
<tr>
<td>EU volumetric element average</td>
<td>69%</td>
<td>54%</td>
<td>58%</td>
</tr>
</tbody>
</table>

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.


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

<table>
<thead>
<tr>
<th>Tariff elements</th>
<th>Number of Member States</th>
<th>Member State</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time-of-use tariffs</td>
<td>17</td>
<td>AT, HR, CZ, DK, FI, FR, EE, GR, IR, LU, LT, MT, PL, PT, SI, ES, UK</td>
</tr>
<tr>
<td>Critical peak pricing</td>
<td>1</td>
<td>FR</td>
</tr>
<tr>
<td>“Social tariff element” to cross-subsidize low income consumer</td>
<td>5</td>
<td>ES, IT, FR, GR, PT</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Member State</th>
<th>Connection Charge</th>
<th>Use of system charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>Deep</td>
<td>No</td>
</tr>
<tr>
<td>Belgium</td>
<td>Shallow</td>
<td>Yes</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>Deep</td>
<td>N/A</td>
</tr>
<tr>
<td>Croatia</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Cyprus</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>Deep</td>
<td>N/A</td>
</tr>
<tr>
<td>Denmark</td>
<td>Shallow</td>
<td>Yes</td>
</tr>
<tr>
<td>Estonia</td>
<td>Deep</td>
<td>N/A</td>
</tr>
<tr>
<td>Finland</td>
<td>N/A</td>
<td>Yes</td>
</tr>
<tr>
<td>France</td>
<td>Semi-deep</td>
<td>No</td>
</tr>
<tr>
<td>Germany</td>
<td>Shallow</td>
<td>No</td>
</tr>
<tr>
<td>Greece</td>
<td>Shallow</td>
<td>N/A</td>
</tr>
<tr>
<td>Hungary</td>
<td>Semi-shallow</td>
<td>N/A</td>
</tr>
<tr>
<td>Ireland</td>
<td>Shallow</td>
<td>No</td>
</tr>
<tr>
<td>Italy</td>
<td>Shallow</td>
<td>Yes</td>
</tr>
<tr>
<td>Latvia</td>
<td>Deep</td>
<td>N/A</td>
</tr>
<tr>
<td>Lithuania</td>
<td>Semi-shallow</td>
<td>N/A</td>
</tr>
<tr>
<td>Luxembourg</td>
<td>N/A</td>
<td>Yes</td>
</tr>
<tr>
<td>Malta</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Netherlands</td>
<td>Shallow</td>
<td>Yes</td>
</tr>
<tr>
<td>Norway</td>
<td>Shallow</td>
<td>N/A</td>
</tr>
<tr>
<td>Poland</td>
<td>Shallow</td>
<td>N/A</td>
</tr>
<tr>
<td>Portugal</td>
<td>Deep</td>
<td>No</td>
</tr>
<tr>
<td>Romania</td>
<td>Semi-deep</td>
<td>N/A</td>
</tr>
<tr>
<td>Slovakia</td>
<td>Deep</td>
<td>N/A</td>
</tr>
<tr>
<td>Slovenia</td>
<td>Shallow</td>
<td>N/A</td>
</tr>
<tr>
<td>Spain</td>
<td>Deep</td>
<td>No</td>
</tr>
<tr>
<td>Sweden</td>
<td>Semi-deep</td>
<td>Yes</td>
</tr>
<tr>
<td>UK</td>
<td>Semi-shallow</td>
<td>Yes</td>
</tr>
</tbody>
</table>

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\textsuperscript{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\textsuperscript{171}.

Moreover, different approaches are applied on how regulatory frameworks stimulate DSOs to deploy innovative technologies. According to Eurelectric \textsuperscript{172} in the majority of Member States analysed (13 out of 20), the regulatory framework is either neutral or hampers innovation and R&D\textsuperscript{173} in distribution systems.

3.3.3. \textit{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.

\begin{footnotesize}
\begin{itemize}
\item \textsuperscript{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).
\item \textsuperscript{171} "From distribution networks to smart distribution systems: Rethinking the regulation of European Electricity DSOs" (2013) THINK.
\item \textsuperscript{172} "Innovation incentives for DSOs – a must in the new energy market development” (2016) EURELECTRIC.
\item \textsuperscript{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.
\end{itemize}
\end{footnotesize}
CEER\(^\text{174}\) and ACER\(^\text{175}\) 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\(^\text{176}\).

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.

\(^\text{174}\) *The future role for DSOs* (2015) CEER.

\(^\text{175}\) *A Bridge to 2025 Conclusions Paper* (2014) ACER.

\(^\text{176}\) 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](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. Comparison of the options**

*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.
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\textsuperscript{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.

\textbf{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. \textit{Impacts on public administrations}

Impacts on public administration are summarized in Section 7 below.

d. \textit{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. \textit{Which Option is preferred and why?}

Distribution network tariffs and remuneration of DSOs (tables 1 and 2 in Section 3.3.1)

\textbf{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. \textbf{Subsidiarity}

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.

\textsuperscript{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 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?"

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\(^\text{179}\) 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-

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;"
Distribution network tariffs and DSO remuneration
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.

<table>
<thead>
<tr>
<th>Description</th>
<th>Option 0</th>
<th>Option 1</th>
<th>Option 2</th>
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<tbody>
<tr>
<td><strong>Option 0</strong> Maintain <em>status quo</em>, 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.</td>
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<tr>
<td><strong>Option 1</strong> 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.</td>
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<tr>
<td><strong>Option 2</strong> Providing for more centralised institutional structures with additional powers and/or responsibilities for the involved entities.</td>
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<tr>
<td><strong>Pros</strong> Lowest political resistance.</td>
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<td></td>
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<tr>
<td><strong>Cons</strong> The implementation of the Third Package and network codes is not sufficient to overcome existing shortcomings of the institutional framework.</td>
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<tr>
<td><strong>Pros</strong> Addresses the shortcomings identified and provides a pragmatic and flexible approach by combining bottom-up initiatives and top-down steering of the regulatory oversight.</td>
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<tr>
<td><strong>Cons</strong> Requires strong coordination efforts between all involved institutional actors.</td>
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<tr>
<td><strong>Pros</strong> Addresses the shortcomings identified with limited coordination requirements for institutional actors.</td>
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<tr>
<td><strong>Cons</strong> Significant changes to established institutional processes with the greatest financial impact and highest political resistance.</td>
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**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), 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**

- **Council of Ministers**
- **European Parliament**
- **European Commission**
- **Agency for the Cooperation of Energy Regulators (ACER)**
- **European Networks for Transmission System Operators for Electricity and for Gas (ENTSO-E and ENTSOG)**
- **National regulatory authorities (NRAs)**
- **Transmission system operators (TSOs)**

*Source: European Commission*

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, the regulatory framework was fragmented and lacked coherence at the regional and European level. The creation of ACER was aimed at addressing these issues by providing a single point of contact for cross-border regulatory issues, thereby facilitating cooperation and ensuring a more harmonized approach to energy regulation across the EU.

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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).
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 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.


\(^{183}\) 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.
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 framework 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.

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.

**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 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.

**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.

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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.
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
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\textsuperscript{190}.

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\textsuperscript{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, 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 and concluded that ACER has become a credible and respected institution playing a prominent role in the EU regulatory field while focusing on the right priorities. Also,

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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.

according to ACER\textsuperscript{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 framework. 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\textsuperscript{195}. Ultimately this fragmented regulatory oversight might constitute a barrier to the integration of the energy markets\textsuperscript{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\textsuperscript{197} and to take decisions\textsuperscript{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 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

\textsuperscript{194} “Energy Regulation: A Bridge to 2025 Conclusions Paper” (19 September 2014) ACER Report.

\textsuperscript{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.

\textsuperscript{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.


\textsuperscript{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.
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 successful overall, the practice of the last 5 years has highlighted the existence of structural insufficiencies. 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.

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. 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.

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

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.
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.

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


\(^{202}\) 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).
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 BAU 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\textsuperscript{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 Third 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.

Option 1: Upgrade the EU institutional framework

Option 1 foresees adapting the EU institutional framework to the new realities of the electricity system\textsuperscript{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

\textsuperscript{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)

\textsuperscript{204} As further detailed in Section 1 of the main body of this impact assessment.

Improving the institutional framework
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.

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\textsuperscript{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 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.

\textsuperscript{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 crucial role in delivering on the common EU objectives and in particular in protecting the European 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.
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.
<table>
<thead>
<tr>
<th>ISSUE</th>
<th>Option 0: Business as usual</th>
<th>Option 1: Upgrade EU institutional framework to address regulatory gaps</th>
<th>Option 2: Restructure EU institutional framework</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ACER decision-making</strong></td>
<td>Limited, through recommendations and opinions</td>
<td>ACER decisions with BoR favourable opinion, also replacing Guideline implementing “all NRA” decisions at EU and regional levels</td>
<td>ACER decision without BoR involvement, mainly by ACER Director</td>
</tr>
<tr>
<td></td>
<td>Most regulatory decisions with BoR favourable opinion</td>
<td>Framework of regional NRA decision-making with ACER oversight (complementary role to safeguard EU interest)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>ACER Director manages ACER and tables proposals for BoR favourable opinion</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>BoR decision-making</strong></td>
<td>2/3rd majority for the most of ACER decisions</td>
<td>Simple majority for most of ACER decisions</td>
<td>2/3rd majority for ACER decisions in a limited instances</td>
</tr>
<tr>
<td><strong>Board of Appeal</strong></td>
<td>Independent body for all appeal cases</td>
<td>Independent body for all appeal cases with strengthened framework and separate budget line in the ACER budget</td>
<td>Independent body for all appeal cases with strengthened line of financing and framework</td>
</tr>
<tr>
<td></td>
<td>Some of its costs are envisaged in the ACER budget</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>ACER Financing</strong></td>
<td>Community/EU-funding (separate budget line)</td>
<td>Need for increased financing (possibly through increased EU-funding and possibly co-financing by contributions by market participants and/or national public authorities)</td>
<td>Need for significantly increased financing (possibly through increased EU-funding and possibly co-financing by contributions by market participants and/or national public authorities)</td>
</tr>
<tr>
<td></td>
<td>Possibility for ACER to collect fees for individual decisions</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Network Code development process</strong></td>
<td>Based on ACER’s framework guideline ENTSO-E drafts network code (strong role and influence), ACER provides opinion and recommendation to the Commission</td>
<td>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 submits the final product to the Commission</td>
<td>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 submits the final product to the Commission</td>
</tr>
<tr>
<td><strong>Oversight of ENTSO-E</strong></td>
<td>Limited ACER oversight of ENTSO-E</td>
<td>Strengthened ACER oversight of ENTSO-E</td>
<td>Strengthened ACER oversight of ENTSO-E</td>
</tr>
</tbody>
</table>
### Oversight of new entities

<table>
<thead>
<tr>
<th>None or limited regulatory oversight (limited rules in network codes and guidelines)</th>
<th>Strengthened regulatory oversight by NRAs and ACER</th>
<th>ACER direct oversight</th>
</tr>
</thead>
</table>

### ENTSO-E’s mission and transparency

<table>
<thead>
<tr>
<th>Lack of clear European mission and voluntary transparency rules</th>
<th>Codified clear European mission and transparency obligations on its decision-making</th>
<th>Formal separation from its members’ interests and creation of a decision-making body</th>
</tr>
</thead>
</table>

### DSO

<table>
<thead>
<tr>
<th>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</th>
<th>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.</th>
<th>Same as Option 1, plus an increased role for coordination and oversight on the part of ACER</th>
</tr>
</thead>
</table>

*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>
<thead>
<tr>
<th>Criteria</th>
<th>Option 0: Business as usual</th>
<th>Option 1: Upgrade EU institutional framework addressing regulatory gaps</th>
<th>Option 2: Restructure EU institutional framework</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quality</td>
<td>0</td>
<td>+</td>
<td>+</td>
</tr>
<tr>
<td></td>
<td>Progress remains limited and primarily voluntary</td>
<td>Using expertise from established actors</td>
<td>Efficient through limited coordination requirements</td>
</tr>
<tr>
<td>Speed of implementation</td>
<td>-</td>
<td>0/+</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Slow, primarily voluntary progress</td>
<td>Building upon established structures</td>
<td>Delays resulting from changed structure</td>
</tr>
<tr>
<td>Use of established institutional processes</td>
<td>-</td>
<td>++</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Efficiency of established processes limited.</td>
<td>Can build upon established structures</td>
<td>Requires building up new structures/processes</td>
</tr>
<tr>
<td>Efficient organisational structure</td>
<td>0</td>
<td>++</td>
<td>+</td>
</tr>
<tr>
<td></td>
<td>Existence of insufficient rules and regulatory gaps for organisation</td>
<td>Efficient organisational structure can be created; using expertise from established actors further improving it</td>
<td>Efficient because of limited coordination requirements</td>
</tr>
<tr>
<td>Involvement of stakeholders</td>
<td>0</td>
<td>+</td>
<td>+</td>
</tr>
<tr>
<td></td>
<td>Process in the hands of the main actors</td>
<td>Rules for effective, reinforced involvement</td>
<td>Rules for effective, reinforced involvement</td>
</tr>
</tbody>
</table>

*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

<table>
<thead>
<tr>
<th>Option</th>
<th>Internal Market for electricity</th>
<th>Transparency and non-discrimination</th>
<th>Administrative impact and implementation costs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Option 0</strong>: Business as usual</td>
<td>0/+</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td><strong>Option 1</strong>: Upgrading EU institutional framework</td>
<td>+</td>
<td>+</td>
<td>0/-</td>
</tr>
<tr>
<td><strong>Option 2</strong>: Restructuring EU institutional framework</td>
<td>++</td>
<td>++</td>
<td>--</td>
</tr>
</tbody>
</table>

*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. 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-

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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\textsuperscript{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\textsuperscript{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\textsuperscript{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. \textit{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\textsuperscript{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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\textsuperscript{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 \textit{status quo} as regards the institutional framework.

\textsuperscript{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.

\textsuperscript{209} For example, the Third Package, in the Gas Regulation established the European Network for Transmission System Operators for Gas (Art. 5).

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\textsuperscript{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**

<table>
<thead>
<tr>
<th>Function</th>
<th>(a) No. extra staff (MIN)</th>
<th>(b) No. extra staff (MAX)</th>
<th>Budget of (a) (million euros)</th>
<th>Budget of (b) (million euros)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Codes and Regulation</td>
<td>7</td>
<td>12</td>
<td>0.938</td>
<td>1.618</td>
</tr>
<tr>
<td>Regulatory Oversight</td>
<td>6</td>
<td>10</td>
<td>0.804</td>
<td>1.340</td>
</tr>
<tr>
<td>Coordination (Internal and External)</td>
<td>2</td>
<td>3</td>
<td>0.268</td>
<td>0.402</td>
</tr>
<tr>
<td>DSO-related</td>
<td>2</td>
<td>3</td>
<td>0.268</td>
<td>0.402</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>+ 17</strong></td>
<td><strong>+ 28</strong></td>
<td><strong>2.278</strong></td>
<td><strong>3.752</strong></td>
</tr>
</tbody>
</table>

*Source: Own calculation based on DG BUDG figures*

\textsuperscript{211} Circular note of DG BUDGET to RUF/2015/34 of 09.12.15
### Table 6: ACER staff: budgetary implications under Option 2

<table>
<thead>
<tr>
<th>Function</th>
<th>(a) No. extra staff (MIN)</th>
<th>(b) No. extra staff (MAX)</th>
<th>Budget of (a) (million euros)</th>
<th>Budget of (b) (million euros)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Codes and Regulation</td>
<td>20</td>
<td>30</td>
<td>2.680</td>
<td>4.020</td>
</tr>
<tr>
<td>Regulatory Oversight</td>
<td>30</td>
<td>35</td>
<td>4.020</td>
<td>4.690</td>
</tr>
<tr>
<td>Dedicated national desk offices</td>
<td>56</td>
<td>84</td>
<td>7.504</td>
<td>11.256</td>
</tr>
<tr>
<td>Reinforced Board of Appeal</td>
<td>15</td>
<td>20</td>
<td>2.010</td>
<td>2.680</td>
</tr>
<tr>
<td>Coordination (Internal and External) &amp; Management</td>
<td>15</td>
<td>20</td>
<td>2.010</td>
<td>2.680</td>
</tr>
<tr>
<td>DSO-related</td>
<td>5</td>
<td>10</td>
<td>0.670</td>
<td>1.340</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>+ 141</td>
<td>+ 199</td>
<td>19.296</td>
<td>26.666</td>
</tr>
</tbody>
</table>

*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 electricity 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. 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 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.

212 ACER's position on the regulatory oversight of (new) entities performing monopoly or near-monopoly functions at EU-wide or regional level.
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.
<table>
<thead>
<tr>
<th>4. DETAILED MEASURES ASSESSED UNDER PROBLEM AREA II, OPTION 2(1); (IMPROVED ENERGY MARKETS, NO CMS)</th>
</tr>
</thead>
</table>
Improving the institutional framework
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.

<table>
<thead>
<tr>
<th>Option 0: Business as usual</th>
<th>Option 1: Eliminate all price caps</th>
<th>Option 2: Create obligation to set price caps, where they exist, at VoLL</th>
</tr>
</thead>
<tbody>
<tr>
<td>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</td>
<td>Eliminate price caps altogether for balancing, intraday and day-ahead markets</td>
<td>Reinforced requirement to set price limits taking “into account an estimation of the value of lost load”</td>
</tr>
<tr>
<td>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.</td>
<td>Removes barriers for scarcity pricing Avoids setting of VoLL (for the purpose of removing negative effects of price caps)</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Description</strong></td>
<td><strong>Pros</strong></td>
<td><strong>Cons</strong></td>
</tr>
<tr>
<td>Simple to implement – leaves administration to technical implementation of the CACM Guideline.</td>
<td>Measure simple to implement; unequivocally and creates legal certainty.</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Pros</strong></td>
<td><strong>Cons</strong></td>
<td><strong>Most suitable Option(s): Option 2</strong> - 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.</td>
</tr>
<tr>
<td><strong>Most suitable Option(s): Option 2</strong> - 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.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Removing price caps
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). 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, [https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricity_gb.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricity_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
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\(^{214}\) 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.

\(^{214}\) 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 3000 euros/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 accurate 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.
Removing price caps

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 explicit 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 than 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."

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."

Further details can be found in the position paper by Wind Europe:

Removing price caps
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.

<table>
<thead>
<tr>
<th>Option 0</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>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 <em>status quo.</em></td>
<td>Move to a nodal pricing system</td>
<td>Introduce locational signals by new means, i.e. through transmission tariffs</td>
<td>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 capacity in order to resolve internal congestions.</td>
</tr>
<tr>
<td>Description</td>
<td>Description</td>
<td>Description</td>
<td>Description</td>
</tr>
<tr>
<td>Approach already agreed.</td>
<td>Theoretically, nodal pricing is the most optimal pricing system for electricity markets and networks.</td>
<td>Would unlock alternative means to provide locational signals for investment and dispatch decisions.</td>
<td>This improvement will render revisions of bidding zones a more technical decision. It will also increase the available cross-zonal capacity.</td>
</tr>
<tr>
<td>Pros</td>
<td>Cons</td>
<td>Pros</td>
<td>Cons</td>
</tr>
<tr>
<td>Risks maintenance of the <em>status quo,</em> and therefore misses the opportunity to address issues in the internal market.</td>
<td>Nodal pricing implies a complete, fundamental overhaul of current grid management and electricity trading arrangements with very substantial transition costs.</td>
<td>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.</td>
<td>Does not address a situation where the results of the bidding zone review are sub-optimal. I.e. this option only covers procedural issues.</td>
</tr>
</tbody>
</table>

**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. to fundamentally change how locational signals are provided, would be disproportionate.
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." 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.

**Figure 1, Current bidding zone configuration**

![Map of Europe showing current bidding zones](image)

*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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216 Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets

217 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. Overall, the total welfare loss due to loop flows was estimated to be around 450 million euros in 2014.

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), 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.

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ENTSO-E Transparency Platform, at [https://transparency.entsoe.eu/](https://transparency.entsoe.eu/)


[https://www.ofgem.gov.uk/sites/default/files/docs/2014/10/fta_bidding_zone_configuration_literature_review_1.pdf](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\(^{221}\). More specifically, once a review is launched\(^{222}\), 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**

![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.

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\(^{221}\) In practice, work has already started on this.

\(^{222}\) Which can be done by ACER, NRAs, Member States or TSOs, depending on specific criteria – Article 32
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. 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."224

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.

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224 Repowering markets

Improving locational price signals
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."\textsuperscript{225}

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),**

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{ratio_graph.png}
\caption{Ratio between available NRC and aggregated thermal capacity of interconnectors – 2014 (%, MW).}
\end{figure}

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

\textsuperscript{225} Annex 1 section 1.7

Improving locational price signals
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\textsuperscript{226}.

Figure 6: Monthly average NTC as part of total transfer capacity (2009-2016).

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{ntc.png}
\caption{Monthly average NTC as part of total transfer capacity (2009-2016).}
\end{figure}

Source: energinet.dk as reported by the Danish Energy Regulatory Authority\textsuperscript{227}

4.2.3. \textit{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 \textit{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.

\textsuperscript{226} 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.

\textsuperscript{227} "STUDY ON CAPACITY REDUCTIONS ON THE GERMAN – WESTERN DANISH BORDER (DE-DKI) (Tender for Offers)" - \url{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. *Presentation of the options*

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
charges are based on capacity, it becomes part of a generator’s 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 derogation subject to regulatory 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\(^\text{228}\) to around 800 million euros\(^\text{229}\).

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\(^\text{230}\) found that there would be overall savings in the

\(^{228}\) Bauer, ibid.


\(^{230}\) Comprising of AT, CH, DE, NL, VE and FR
total cost of electricity 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.\textsuperscript{231}

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. \textit{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

\textsuperscript{231} 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 price 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.**

<table>
<thead>
<tr>
<th>Description</th>
<th>Option 0: Business as usual</th>
<th>Option 1:Restrict charges on producers (G-charges)</th>
<th>Option 2: Set clearer principles for transmission charges</th>
<th>Option 3: Harmonisation transmission tariffs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pros</strong></td>
<td>This option would see the status quo maintained, and transmission tariffs set according to the requirements under Directive 72 and the ITC regulation.</td>
<td>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)</td>
<td>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.</td>
<td>Full harmonisation of transmission tariffs.</td>
</tr>
<tr>
<td><strong>Cons</strong></td>
<td>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.</td>
<td>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).</td>
<td>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.</td>
<td>Minimises distortion between Member States on both investment and dispatch; creates a level-playing field.</td>
</tr>
<tr>
<td><strong>Most suitable option(s): Option 2</strong></td>
<td>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.</td>
<td>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.</td>
<td>Still leaves the door open for variation in national approaches; will not resolve all potential issues.</td>
<td>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.</td>
</tr>
</tbody>
</table>
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**

<table>
<thead>
<tr>
<th>Building block</th>
<th>Notes:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation / load</td>
<td>Are transmission tariffs levied on generation or load, or both? Do</td>
</tr>
<tr>
<td></td>
<td>transmission tariffs apply to embedded generation?</td>
</tr>
<tr>
<td>Capacity vs. commodity</td>
<td>Are tariffs levied on a MW (capacity) basis or MWh production/consumption basis?</td>
</tr>
<tr>
<td>Locational charging?</td>
<td>Are transmission tariffs locationally differentiated (with locational signals) or uniform?</td>
</tr>
<tr>
<td>Zonal vs. nodal?</td>
<td>If transmission tariffs are locational, do tariffs differ by node or do they differ by zone?</td>
</tr>
<tr>
<td>Time of day signals?</td>
<td>Do transmission tariffs provide economic incentives for time of use of the transmission network?</td>
</tr>
<tr>
<td>Types of cost</td>
<td>What types of costs does the transmission tariff recover?</td>
</tr>
<tr>
<td>Cost recovery</td>
<td>Are tariffs based on short or long term costs? Are tariffs based on marginal or average costs? How is full cost recovery achieved?</td>
</tr>
<tr>
<td>Connection regime</td>
<td>Are use of system charging arrangements accompanied by shallow or deep connection charging arrangements?</td>
</tr>
</tbody>
</table>

*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 and sufficiently in advance of their entry into force.

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. This regulation sets down limits on the average annual transmission charges that can be applied in each Member State to electricity producers. 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, 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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232 Art 37(1)(a)
233 Art 37(6)(a)
235 0-2 EUR/MWh in Romania; 0-2.5 EUR/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.
236 "Transmission tariff harmonisation supports competition", a report prepared for Energy Norway, May 2013

Minimise investment and dispatch distortions due to transmission tariff structures
Subsequently, and with the possibility existing to develop a ‘network code’ 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. 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.

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237 A Commission Regulation developed under procedures laid down in the Electricity Regulation.

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. Presentation of the options

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:

- 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

239 Excluding Austria and Belgium, who apply energy-based charges for ancillary services and/or losses
more concrete legal measures in the future, notably through 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. Comparison of the options

G-Charges

The option to remove energy-based transmission tariffs on generators has been assessed quantitatively based on ECN’s COMPETES model\textsuperscript{240}. 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 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\textsuperscript{241}, TSO surplus\textsuperscript{242}, payments by consumers\textsuperscript{243} and producer surplus\textsuperscript{244} 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

\begin{itemize}
  \item \textsuperscript{240} “Transmission Tariffs and Congestion Income Policies”, ECN, DCision, Trinomics (Intermediate Report)
  \item \textsuperscript{241} \text{Generation OPEX + Generation CAPEX + Fixed O&M + Transmission Investment}
  \item \textsuperscript{242} \text{G-charge payments + Congestion income - Transmission CAPEX}
  \item \textsuperscript{243} \text{Payments consumers make for their electricity use, i.e. electricity use (in MWh) x electricity price (in Euro/MWh)}
  \item \textsuperscript{244} \text{Short run profits - Gen CAPEX - G-charge payments}
\end{itemize}
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 \( \text{Change in TSO surplus} + \text{Change in Producer surplus} - \text{Change in Consumer payments} \). 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)**

<table>
<thead>
<tr>
<th></th>
<th>System Costs</th>
<th>TSO surplus</th>
<th>Consumer payments</th>
<th>Producer surplus</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference (no tariffs)</td>
<td>85,082.2</td>
<td>2,102.3</td>
<td>226,821.0</td>
<td>138,455.7</td>
</tr>
<tr>
<td>Option 0 (current situation)</td>
<td>85,094.7</td>
<td>3,044.6</td>
<td>227,617.6</td>
<td>138,282.9</td>
</tr>
<tr>
<td>Option 1 (cap.-based tariffs)</td>
<td>85,094.0</td>
<td>2,875.1</td>
<td>227,298.2</td>
<td>138,141.1</td>
</tr>
</tbody>
</table>

**Table 2 – option comparison, all countries (million EUR)**

<table>
<thead>
<tr>
<th></th>
<th>System Costs</th>
<th>TSO surplus</th>
<th>Consumer payments</th>
<th>Producer surplus</th>
<th>Social welfare</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 0 vs Reference</td>
<td>12.5</td>
<td>942.3</td>
<td>796.6</td>
<td>-172.8</td>
<td>-27.1</td>
</tr>
<tr>
<td>Option 1 vs Reference</td>
<td>11.8</td>
<td>772.8</td>
<td>477.2</td>
<td>-314.6</td>
<td>-19.0</td>
</tr>
<tr>
<td>Option 1 vs Option 0</td>
<td>-0.8</td>
<td>-169.5</td>
<td>-319.4</td>
<td>-141.8</td>
<td>8.1</td>
</tr>
</tbody>
</table>

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 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 risk 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 to 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. 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.

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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245 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.

246 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. 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

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247 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\textsuperscript{248}, 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."

\textsuperscript{248} "Electricity market design: Fit for the low carbon transition," Eurelectric (2016)
Minimise investment and dispatch distortions due to transmission tariff structures
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

<table>
<thead>
<tr>
<th>Description</th>
<th>Option 0: Business as usual</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Description</td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>Pros</td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
</tr>
<tr>
<td>Cons</td>
<td>Missing a potentially significant source of income which could be spent on interconnection and removing the biggest bottlenecks in the EU.</td>
<td>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.</td>
<td>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.</td>
<td>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.</td>
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</table>

**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 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). 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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249 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.


*Congestion income spending to increase cross-border capacity*
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\(^{251}\). 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.

\(^{251}\) 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)


4.4.3. **Deficiencies of the current legislation**

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
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. **Subsidiarity**

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 redispach 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 redispaching] 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."
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))
Congestion income spending to increase cross-border capacity
5.1. Improved resource adequacy methodology
## 5.1.1. Summary table

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**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\textsuperscript{252}, 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\textsuperscript{253} 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.

\textsuperscript{252} 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.

\textsuperscript{253} 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.

The Council of European Energy Regulators (CEER) 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 used in the different Member States, the methodologies differ greatly depending on the targeted timeframe 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. 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.

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254 JRC (2016), “Generation adequacy methodologies review”
256 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.
257 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).
258 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.
259 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. In addition, there are also various ways generation from variable output (i.e. intermittent RES) is modelled; 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 which simply compare the sum of all nameplate generation capacities with the peak demand in a single one-off moment – by more complex ‘**probabilistic**’ 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.
Nonetheless, these adequacy methodologies\textsuperscript{264} still differ (deterministic vs. stochastic).

- Despite on-going developments, some assessments are still considering isolated systems and/or developing ways to include interconnectors\textsuperscript{265}. 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\textsuperscript{266}, and for country-wide modelling, the "copperplate approach" prevails\textsuperscript{267}.

- 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\textsuperscript{268}. In most cases, the assessment is carried out yearly.

\textsuperscript{264} 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.

\textsuperscript{265} 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).

\textsuperscript{266} 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.

\textsuperscript{267} 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).

\textsuperscript{268} 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

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<td>Capacity Margin</td>
</tr>
<tr>
<td>France</td>
<td>Y</td>
<td>TSO</td>
<td>LOLE</td>
<td>Portugal</td>
<td>Y</td>
<td>TSO + Gov</td>
<td>Load Supply Index (supply/demand per hour)</td>
</tr>
<tr>
<td>Germany</td>
<td>Y</td>
<td>TSO + NRA</td>
<td>Calculation of EENS, LOLE, LOLP and Capacity Margin</td>
<td>Spain</td>
<td>Y</td>
<td>TSO</td>
<td>Capacity Margin</td>
</tr>
<tr>
<td>Ireland</td>
<td>Y</td>
<td>TSO + NRA</td>
<td>Probabilistic assessment based primarily on LOLE</td>
<td>Sweden</td>
<td>Y</td>
<td>TSO</td>
<td>EENS, LOLE and LOLP are measured</td>
</tr>
</tbody>
</table>

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:\(^269\):

- 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)\(^270\).

- 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.

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\(^269\) JRC Science for Policy Report (2016), "Generation adequacy methodologies review"

\(^270\) 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\(^{271}\) ("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\(^{272}\) 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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\(^{271}\) An inter-governmental initiative designed to promote collaboration on cross-border exchange of electricity in Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland.

\(^{272}\) 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

<table>
<thead>
<tr>
<th>Approach</th>
<th>PLEF</th>
<th>ENTSO-E</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Current</td>
<td>Targeted</td>
</tr>
<tr>
<td>Scale</td>
<td>Probabilistic</td>
<td>Deterministic</td>
</tr>
<tr>
<td></td>
<td>Regional (at least direct neighbours, up to second degree neighbours)</td>
<td>National – simplified regional</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Pan European</td>
</tr>
<tr>
<td>Network representation</td>
<td>Current (NTC(^{273})) and targeted (PTDF(^{274}))</td>
<td>None on small scale, maximum flows on regional scale</td>
</tr>
<tr>
<td></td>
<td></td>
<td>First, NTC Later, possibly flow-based</td>
</tr>
<tr>
<td>Security of supply indicators</td>
<td>Loss of load (energy duration, probability, frequency,...), capacity margin</td>
<td>Capacity margin</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Loss of load</td>
</tr>
<tr>
<td>Uncertainty considerations</td>
<td>Monte Carlo simulations</td>
<td>Additional margins</td>
</tr>
</tbody>
</table>

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 arguing 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"\(^{275}\). 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"\(^{276}\).

\(^{273}\) 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.

\(^{274}\) Power Transfer Distribution Factor

\(^{275}\) CEER (2014), Recommendations for the assessment of electricity generation adequacy

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". 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." 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

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Improved resource adequacy methodology
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 probabilistic calculations\(^{279}\) 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;

\(^{279}\) 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...)²⁸⁰

iv. It should calculate resource adequacy indicators for all countries (LOLE, EENS, etc.)

v. It should appropriately take into account foreign generation, interconnection capacity, RES²⁸¹, 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 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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²⁸⁰ This means considering flexibility issues, temporal constraints and a realistic evaluation of the expected role of interconnectors.

²⁸¹ 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.

²⁸² 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. 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 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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283 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 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.

284 "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\textsuperscript{285} – 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 fleets (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 the EU, which represents 31\% of the installed gas capacities, can be saved with cooperation in investments. This represents a gain of EUR 4.8\textsuperscript{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.

\textsuperscript{285} The scope of the model comprises EU28 + (CH, NO, BA, MK, ME, RS) and 50 years of weather data.
Improved resource adequacy methodology

Figure 2 – Capacity savings for METIS EuCO27 in GW

<table>
<thead>
<tr>
<th>Zone</th>
<th>Capacity savings (in GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EU28</td>
<td>79</td>
</tr>
<tr>
<td>AT</td>
<td>3</td>
</tr>
<tr>
<td>BE</td>
<td>2</td>
</tr>
<tr>
<td>BG</td>
<td>0</td>
</tr>
<tr>
<td>CY</td>
<td>0</td>
</tr>
<tr>
<td>CZ</td>
<td>0</td>
</tr>
<tr>
<td>DE</td>
<td>14</td>
</tr>
<tr>
<td>DK</td>
<td>2</td>
</tr>
<tr>
<td>EE</td>
<td>0</td>
</tr>
<tr>
<td>ES</td>
<td>3</td>
</tr>
<tr>
<td>FI</td>
<td>3</td>
</tr>
<tr>
<td>FR</td>
<td>10</td>
</tr>
<tr>
<td>GR</td>
<td>3</td>
</tr>
<tr>
<td>HR</td>
<td>1</td>
</tr>
<tr>
<td>HU</td>
<td>2</td>
</tr>
<tr>
<td>IE</td>
<td>1</td>
</tr>
<tr>
<td>IT</td>
<td>6</td>
</tr>
<tr>
<td>LT</td>
<td>0</td>
</tr>
<tr>
<td>LU</td>
<td>1</td>
</tr>
<tr>
<td>LV</td>
<td>1</td>
</tr>
<tr>
<td>MT</td>
<td>0</td>
</tr>
<tr>
<td>NL</td>
<td>7</td>
</tr>
<tr>
<td>PL</td>
<td>6</td>
</tr>
<tr>
<td>PT</td>
<td>2</td>
</tr>
<tr>
<td>RO</td>
<td>3</td>
</tr>
<tr>
<td>SE</td>
<td>6</td>
</tr>
<tr>
<td>SI</td>
<td>0</td>
</tr>
<tr>
<td>SK</td>
<td>0</td>
</tr>
<tr>
<td>UK</td>
<td>4</td>
</tr>
</tbody>
</table>

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 equipment 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. 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.

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)**

- 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)**

Impact for businesses and public authorities

The administrative costs\(^{287}\) 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

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\(^{287}\) 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 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

<table>
<thead>
<tr>
<th>Quality of the methodology</th>
<th>Option 0: No further action</th>
<th>Option 1: Harmonisation of national assessments</th>
<th>Option 2: ENTSO-E provides for single methodology, Member States carry out the assessment</th>
<th>Option 3: ENTSO-E provides for single methodology and carries out the assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>-- No progress or uncertain progress as it depends on Member State independent initiatives</td>
<td>0 Progress remains limited as only harmonisation</td>
<td>++ Efficient as there is a single methodology</td>
<td>+/− Coherence as ENTSO-E runs the same model for all Member States and the pan-European assessments. Input and output data are more coherent.</td>
</tr>
<tr>
<td>Use of established institutional processes</td>
<td>- Unclear which processes to be used</td>
<td>+ Can build upon established processes</td>
<td>0/+ Can partially build upon established processes</td>
<td>− Requires building up new processes (ENTSO-E to carry out the assessment)</td>
</tr>
<tr>
<td>Efficient organisational structure</td>
<td>- Each Member State carries out its own assessment</td>
<td>- Each Member State carries out its own assessment</td>
<td>0/- Each Member State carries out its own assessment based on ENTSO-E methodology</td>
<td>++ Efficient as ENTSO-E carries out the assessment for all Member States</td>
</tr>
<tr>
<td>Capacity savings</td>
<td>-- Low capacity savings</td>
<td>- Higher capacity savings due to different treatment of cross-border capacity</td>
<td>+ Higher capacity savings as single methodology</td>
<td>++ Highest capacity savings as single methodology and calculation</td>
</tr>
</tbody>
</table>

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\(^{288}\) 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\(^ {289}\). In addition, ENTSO-E’s target methodology is announced to be "fully in line with the methodology developed by the TSOs of the PLEF\(^ {290}\).

EFET\(^ {291}\) 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\(^ {292}\) 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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\(^ {288}\) Recommendations for the assessment of electricity generation adequacy, CEER
\(^ {289}\) Pentalateral Energy Forum [PLEF] – Support Group 2, Generation Adequacy Assessment
\(^ {290}\) Energy Community Workshop: "Towards Sustainable Development of Energy Community", RES integration: the ENTSO-E perspective
\(^ {291}\) EFET answer to the public consultation on the market design initiative
\(^ {292}\) Wind Europe, "Assessing resource adequacy in an integrated EU power system" (May 2016)
Improved resource adequacy methodology
5.2. Cross-border operation of capacity mechanisms
5.2.1. Summary table

<table>
<thead>
<tr>
<th>Objective: Framework for cross-border participation in capacity mechanisms</th>
<th>Option 0</th>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Description</strong></td>
<td>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.</td>
<td>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.</td>
<td>Option 1 + EU framework harmonising the main features of the capacity mechanisms per category of mechanism (e.g. for market-wide capacity mechanisms, reserves, …).</td>
</tr>
<tr>
<td><strong>Pros</strong></td>
<td>Stronger enforcement The Commission's Guidance on state interventions(^{293}) 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.</td>
<td>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.</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Cons</strong></td>
<td>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, resource providers).</td>
<td>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.</td>
<td>In addition to the drawback of Option 1, it would limit the choice of instruments.</td>
</tr>
</tbody>
</table>

**Most suitable Option(s): Options 1 and 2**

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\(^{294}\).

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 receives 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\(^{295}\) 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 be taken for granted. This could explain why, to date, there are not many practical examples of such cross-border schemes.

\(^{294}\) See Booz & co, 2013, 'Study on the benefits of an integrated European Energy market'
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.296

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 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.

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

296 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.

297 https://www.semcommittee.com/overview?article=f254d505-16bc-4a66-b940-bf2cc7b614ae

299 Cross-border operation of capacity mechanisms
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\(^\text{298}\) and the EEAG require among others that such mechanisms are open and allow for the participation of resources from across the borders.

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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 voluntarily 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

299 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 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 availability 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 foreign capacity remuneration. In this case, foreign capacity is the limiting factor that should receive additional incentives.

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 301 estimated that such cost corresponds roughly to 10% 302 of the overall cost of the design of a CM 303. 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 304 for TSOs and regulators combined. TSOs and regulators have to check pre-qualification and registration

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301 Thema (2016), *Framework for cross-border participation in capacity mechanisms (First interim report)*

302 Costs in the design phase are one-time costs.

303 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).

304 FTEs in other phases refer to (annually) recurring costs.
(eligibility phase) and ensure compliance i.e. monitoring, control, penalties (control/compliance phase). 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 individual 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.

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.

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305 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

<table>
<thead>
<tr>
<th>Option</th>
<th>Option 0: do nothing (EEAG)</th>
<th>Option 1: EU framework for cross-border participation</th>
<th>Option 2: EU framework for cross-border participation + blueprint</th>
</tr>
</thead>
<tbody>
<tr>
<td>Investment distortions due to uncoordinated CMs</td>
<td>- More chance of distorted locational signals and over-capacity in zones with CM</td>
<td>+ Less chance of investment distortions due to effective cross-border scheme</td>
<td>+ Less chance of investment distortions due to effective cross-border scheme</td>
</tr>
<tr>
<td>Overall system costs</td>
<td>- Higher overall system costs</td>
<td>+ Lower overall system costs due to reduction in CM auction price</td>
<td>+ Lower overall system costs due to reduction in CM auction price</td>
</tr>
<tr>
<td>Speed of implementation</td>
<td>- Individual XB arrangements for each border</td>
<td>+ Harmonised XB arrangements across the EU</td>
<td>+ Harmonised XB arrangements across the EU</td>
</tr>
<tr>
<td>Complexity and administrative impact</td>
<td>- High administrative impact for market participants operating in more than one zone</td>
<td>+ Reduced complexity and administrative impact due to harmonised rules</td>
<td>+ Reduced complexity and administrative impact due to harmonised rules</td>
</tr>
</tbody>
</table>

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\textsuperscript{306} 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\textsuperscript{307} "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 unnecessary CMs."

ACER and CEER\textsuperscript{308} "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)."

\textsuperscript{306} EFET response to the public consultation on the Market Design Initiative, 2015
\textsuperscript{307} WindEurope response to the public consultation on the Market Design Initiative, 2015
\textsuperscript{308} ACER-CEER response to European Commission Capacity Mechanism Sector Inquiry, July 2016

Cross-border operation of capacity mechanisms
6. DETAILED MEASURES ASSESSED UNDER PROBLEM AREA III: A NEW LEGAL FRAMEWORK FOR PREVENTING AND MANAGING CRISIS SITUATIONS
### Objective: Ensure a common and coordinated approach to electricity crisis prevention and management across Member States, whilst avoiding undue government intervention

#### Assessments

<table>
<thead>
<tr>
<th>Option 0: Do nothing</th>
<th>Option 0+: Non-regulatory approach</th>
<th>Option 1: Common minimum EU rules for prevention and crisis management</th>
<th>Option 2: Common minimum EU rules plus regional cooperation, building on Option 1</th>
<th>Option 3: Full harmonisation and full decision-making at regional level, building on Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rare/extreme risks and short-term risks related to security of supply are assessed from a national perspective.</td>
<td>This option was disregarded as no means for enhanced implementing of existing acquisition for enhanced voluntary cooperation were identified</td>
<td>Member States to identify and assess rare/extreme risks based on common risk types.</td>
<td>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).</td>
<td>All rare/extreme risks undermining security of supply assessed at the EU level, which would be prevailing over national assessment.</td>
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<tr>
<td>Risk identification &amp; assessment methods differ across Member States.</td>
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#### Plans

<table>
<thead>
<tr>
<th>Option 0: Do nothing</th>
<th>Option 0+: Non-regulatory approach</th>
<th>Option 1: Common minimum EU rules for prevention and crisis management</th>
<th>Option 2: Common minimum EU rules plus regional cooperation, building on Option 1</th>
<th>Option 3: Full harmonisation and full decision-making at regional level, building on Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>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 &amp; preparation (e.g., no common rules on how to tackle cybersecurity risks).</td>
<td>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.</td>
<td>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 &amp; cooperation obligations to Energy Community partners</td>
<td>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.</td>
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<tr>
<td>Crisis management</td>
<td>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).</td>
<td>Minimum common rules on crisis prevention and management (including the management of simultaneous electricity crisis) requiring Member States to: (i) not to unduly interfere 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.</td>
<td>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 agreements and resulting compensation should be described in the Risk Preparedness Plans.</td>
<td>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.</td>
</tr>
<tr>
<td>Monitoring</td>
<td>Monitoring of security of supply predominantly at the national level. ECG as a voluntary information exchange platform.</td>
<td>Systematic discussion of ENTSO-E Seasonal Outlooks in ECG and follow up of their results by Member States concerned.</td>
<td>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.</td>
<td>A European Standard (e.g. for EENS and LOLE) on Security of Supply could be developed to allow performance monitoring of Member States.</td>
</tr>
<tr>
<td>Pros</td>
<td>Cons</td>
<td>Most suitable option(s): Option 2, as it provides for sufficient regional coordination in preparation and managing crisis while respecting national differences and competences.</td>
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<td>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.</td>
<td>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 address simultaneous scarcity situations.</td>
<td>Regional plans would ensure full coherence of actions taken in a crisis.</td>
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<td>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 crisis. 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.</td>
<td>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.</td>
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<tr>
<td>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.</td>
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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 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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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. 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. 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: (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.

| 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. 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

310 See Article 6 of NC ER.
311 See Articles 14 & 15 of NC ER.
312 See Article 35 of NC ER.
313 See Article 8 and 39 of NC ER.
314 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\textsuperscript{315}. 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\textsuperscript{316}. The analysis shows that the risks to be assessed vary considerably\textsuperscript{317}. 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.

\textsuperscript{315} 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.

\textsuperscript{316} 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).

\textsuperscript{317} 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. 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), 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 convocate 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.

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318 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.

319 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).

320 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 interoperability 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^321 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

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^321 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

<table>
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<tr>
<th>Option 0: Baseline scenario</th>
<th>Option 0+: Improved implementation of current legislation without regulatory action at EU level</th>
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<tbody>
<tr>
<td>Option 1: Common minimum rules to be implemented by Member States</td>
<td>Option 2: Common minimum rules to be implemented by Member States plus regional cooperation</td>
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<td>Option 3: Full harmonisation and full decision-making at regional level</td>
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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 situations, and as to how they should co-operate with one another.
The innovative tools 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.

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 simultaneous 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-annually 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.

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.

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/).
Cross-border operation of capacity mechanisms

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 TSO's 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](http://cordis.europa.eu/project/rcn/101320_en.html)

**Web Site:** [http://www.itesla-project.eu/](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
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\textsuperscript{324}, 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 address certain of the problems identified (e.g. Nord-BER, PLEF). However, these initiatives have different levels of ambition and effectiveness, and they geographically 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\textsuperscript{325}, b)...


\textsuperscript{325} 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 30\textsuperscript{th} 2015) or line overheating (leading to declaration of emergency state by the Czech grid operator CEPS on July 25\textsuperscript{th} 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, 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.

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326 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).

327 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 respected328.

- 'Duty to offer assistance': In case crisis arises, Member States should react in a spirit of good cooperation and solidarity329. 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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328 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’.

329 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

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<thead>
<tr>
<th>Nordic Contingency and Crisis Management Forum (NordBER)</th>
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<tbody>
<tr>
<td>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.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pentalateral Energy Forum</th>
</tr>
</thead>
<tbody>
<tr>
<td>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 &quot;development center for new ideas&quot; with the goal to reach specific recommendations.</td>
</tr>
</tbody>
</table>

**Source:** [https://nordber.org/](https://nordber.org/) and [http://www.benelux.int/nl/kernthemas/energie/pentalateral-energy-forum/](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 simultaneous 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 align principles for prioritization 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. 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 address 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, Member States should agree in advance, when and what loads would be curtailed in crisis situations with a cross-border impact. Solidarity measures in simultaneous scarcity, including coordinated demand restrictions

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330 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).

331 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

332 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/#.VpTd2v7IuUk
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.\footnote{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. Appendix 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 subsystems have an equally large deficit, load shedding is distributed thereafter between those subsystems.  
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 occurring 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 Commission 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.

334 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. 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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335 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 region 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.  

336 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

<table>
<thead>
<tr>
<th>Country &amp; year</th>
<th>Number of end-consumers interrupted</th>
<th>Duration, energy not served</th>
<th>Estimated costs to whole society</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sweden/Denmark, 2003</td>
<td>0.86 million (Sweden); 2.4 million</td>
<td>2.1 hours, 18 GWh</td>
<td>EUR 145 – 180 million</td>
</tr>
<tr>
<td></td>
<td>(Denmark)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>France, 1999</td>
<td>1.4 - 3.5 million</td>
<td>2 days–2 weeks, 400 GWh</td>
<td>EUR 11.5 billion</td>
</tr>
<tr>
<td>Italy/Switzerland, 2003</td>
<td>55 million</td>
<td>18 hours</td>
<td></td>
</tr>
<tr>
<td>Sweden, 2005</td>
<td>0.7 million</td>
<td>1 day – 5 weeks, 11 GWh</td>
<td>EUR 400 million</td>
</tr>
<tr>
<td>Central Europe, 2006</td>
<td>45 million</td>
<td>Less than 2 hours</td>
<td></td>
</tr>
</tbody>
</table>

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 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.

337 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. 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.

In addition, it is foreseen to withdraw the current legal obligation for Member States to draw up reports monitoring security of supply, 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.

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338 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.

339 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).

A 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 the 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\(^\text{341}\) show that well integrated markets and regional coordination during periods of extreme weather conditions (i.e. very low temperature\(^\text{342}\)) 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.

\(^{341}\) "METIS Study S16: Weather-driven revenue uncertainty for power producers and ways to mitigate it", Arteays (2016).

\(^{342}\) Even though periods with very low temperature occur rarely (9\(^\circ\) 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). 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**

<table>
<thead>
<tr>
<th>Level</th>
<th>EENS (% of annual load) – ENTSO-E V1 scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>National level</td>
<td>0.36 %</td>
</tr>
<tr>
<td>Regional level</td>
<td>0.02 %</td>
</tr>
<tr>
<td>European level</td>
<td>0.01 %</td>
</tr>
</tbody>
</table>

*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*

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343 "METIS Study S04: Stakes of a common approach for generation and system adequacy", Artelys (2016).
344 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\(^{345}\).

Overall, the costs to develop and to follow a Network Code or Guidelines on cybersecurity 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\(^{346}\). 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\(^{347}\). 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

\(^{345}\) "Benefits of an Integrated European Energy Market (2013)". BOOZ&CO.


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.\(^{348}\)

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\(^{348}\) 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](http://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, over time, 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 facilitate 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\textsuperscript{349} 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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\textsuperscript{349} SWD(2013) 32 final.

Cross-border operation of capacity mechanisms
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\(^{350}\) 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.

\(^{350}\) 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\textsuperscript{351}). 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\textsuperscript{352} and the Florence Forum\textsuperscript{353}.

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)


\textsuperscript{352} See Note to the Permanent Representatives Committee/Council: Messages from the Presidency on electricity market design and regional cooperation, paragraph 7.

\textsuperscript{353} 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
Cross-border operation of capacity mechanisms
7.1. Addressing energy poverty
### 7.1.1. Summary table

<table>
<thead>
<tr>
<th>Objective: Better understanding of energy poverty and disconnection protection to all consumers</th>
<th>Option: 0</th>
<th>Option: 0+</th>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU: sharing of good practices.</td>
<td>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.</td>
<td>Setting an EU framework to monitor energy poverty.</td>
<td>Setting a uniform EU framework to monitor energy poverty, preventative measures to avoid disconnections and disconnection winter moratorium for vulnerable consumers.</td>
<td></td>
</tr>
<tr>
<td>Disconnection safeguards</td>
<td>NRAs to monitor and report figures on disconnections.</td>
<td>NRAs to monitor and report figures on disconnections.</td>
<td>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(^{354}) of disconnections for vulnerable consumers.</td>
<td></td>
</tr>
</tbody>
</table>

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\(^{354}\) 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+.

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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. Description of the baseline

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.\(^{355}\)

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.\(^{356}\) This is well recognised in legislation 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: energy poverty and disconnection safeguards.

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.\(^{358}\)

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.\(^{359}\)

\(^{355}\) Energy poverty and vulnerable consumers in the energy sector across the EU: analysis of policies and measures. (2015). Insight_E.


\(^{357}\) 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.”

\(^{358}\) Energy poverty and vulnerable consumers in the energy sector across the EU: analysis of policies and measures. (2015). Insight_E.

Insight_E identifies high energy bills, low income and poor energy efficiency as the main drivers of energy poverty\(^\text{360}\).

**Figure 1: Drivers of energy poverty**

![Diagram showing the 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\(^\text{361}\) (see Figure below).

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\(^{360}\) Energy poverty and vulnerable consumers in the energy sector across the EU: analysis of policies and measures. (2015). Insight_E.

\(^{361}\) The indicator is measured as part of the Eurostat Survey on Income and Living Conditions (EU-SILC).
Evidence suggests that energy poverty is increasing in Europe. In recent years, energy prices have risen faster than household disposable income\textsuperscript{362}, 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\textsuperscript{363}.

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\textsuperscript{364} increased more than middle-income households. The Figure below presents the EU share of household expenditure on domestic energy between 2000 and 2014.

\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure2.png}
\caption{Percentage of all households and households in poverty that consider they are unable to keep warm}
\end{figure}

\textit{Source: Eurostat – SILC indicators (Inability to keep home adequately warm - Code: ilc_mdes01)}

\textsuperscript{362} Source: Eurostat (Electricity prices for domestic consumers; Gas prices for domestic consumers; disposable income of households per capita; period 2010 – 2014).


\textsuperscript{364} Domestic use refers to heating, lighting and powering appliances.
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\textsuperscript{365} found that countries with the poorest housing (Portugal, Greece, Ireland, the UK) show the highest excess winter mortality.

The Figure below presents EWD\textsuperscript{366} 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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\textsuperscript{366} Excess Winter Deaths = \{[winter death (December – March)]- 0.5[Non-winter deaths (August – November, April – July)] / (average of non-winter deaths)
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 IEA.

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 suppressed:

- 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 suppressed to compete with capital.\(^{367}\)
- 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.\(^{368}\)

These effects combined are likely to suppress 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**

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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\textsuperscript{369}.

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\textsuperscript{370}. Article 3 of the Electricity Directive\textsuperscript{371} and Gas Directive\textsuperscript{372} 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.

\textit{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\textsuperscript{373}, 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.

\textsuperscript{369} 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
\textsuperscript{370} 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.
\textsuperscript{371} “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.”
\textsuperscript{373} Eurostat EU-SILC 2014
Figure 5: Share of customers with electricity disconnections, gas disconnection, and share of population in arrears on utility bills

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. 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

374 "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\textsuperscript{375}.

**Table 1: Summary of disconnection safeguards**

<table>
<thead>
<tr>
<th>Measure</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disconnection prohibition</td>
<td>Moratorium on disconnecting the energy supply (either electricity, gas or both) for all customers, a specific target group or time period (e.g., Winter)</td>
</tr>
<tr>
<td>Debt management</td>
<td>Debt management can include a negotiated a payment plan, delayed payment responsibility or a financial grant to assist with costs.</td>
</tr>
<tr>
<td>Customer engagement</td>
<td>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.</td>
</tr>
</tbody>
</table>

*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.
### Table 2: Disconnection protection safeguards by Member States

| Measures | Focus | AT | BE | BG | CY | CZ | DE | EE | ES | FI | FR | GR | HR | HU | IE | IT | LT | LV | LU | MT | NL | PL | PT | RO | SE | SK | SI | UK |
|----------|-------|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|
| Disconnection prohibition | All consumers | E | E | EG | EG | EG | EG | EG | EG | EG | E | E |
| | Vulnerable consumers/low income/socio-demographic | E | EG | EG | EG | EG | EG | EG | E |
| | Consumers with (or at risk of) medical conditions | E | EG | EG | EG | EG | EG | EG | 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 |
| | All consumers | EG | EG | E | E |
| | Vulnerable consumers/low income/socio-demographic | EG | EG | EG | EG | EG | EG | E | EG |
| | Consumers with (or at risk of) medical conditions | EG | EG | EG | |
| Seasonal measures (winter or certain days/year-round 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 | L | L | |
| | Customer engagement | LV | LV | LV | LV | L | L | LV | LV | L | L | L | LV | L | L | V | |
| Statistics | Elec Discon per 1000 customers | 9.1 | 1.5 | 55.1 | 7.5 | 10.0 | 23.0 | 10.0 | 32.6 | 6.9 | 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 | 4.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 15.1 | 0.0 | 0.0 | 12.0 | |

**Source:** CEER National Indicators Database 2015, INSIGHT_E Country Reports 2015
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.376

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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Addressing energy poverty
**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\(^{377}\).

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\(^{378}\).

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\(^{379}\), 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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\(^{377}\) CEER National Indicators Database 2015

\(^{378}\) "Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers". Forthcoming publication. Insight_E.

\(^{379}\) 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.  

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).

Figure 6: Working days before electricity disconnection, in ascending order for notification period (2014)

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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381 “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**

<table>
<thead>
<tr>
<th>Criterion</th>
<th>Legislation meets criterion</th>
<th>Assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Effectiveness</td>
<td>Partially</td>
<td>Member States define vulnerable consumer and adopt measures to protect them.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Uneven protection of vulnerable consumers.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Lack of data on the scale and drivers of energy poverty.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Growing energy poverty levels across the EU.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Lack of assistance by Member States to address energy poverty.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NRA lack data to fulfil monitoring role.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Some Member States still quote energy poverty as a reason for maintaining</td>
</tr>
<tr>
<td></td>
<td></td>
<td>price regulation and not going ahead with full energy market liberalisation</td>
</tr>
<tr>
<td>Efficiency</td>
<td>Completely</td>
<td>Low costs compared with potential benefits.</td>
</tr>
<tr>
<td>Relevance</td>
<td>Completely</td>
<td>Consumer vulnerability will remain relevant as some drivers of vulnerability</td>
</tr>
<tr>
<td></td>
<td></td>
<td>are permanent.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Energy poverty likely to grow in the future if no policy adopted.</td>
</tr>
<tr>
<td>Coherence</td>
<td>Partially</td>
<td>No inconsistencies with or elements working against objectives of the</td>
</tr>
<tr>
<td></td>
<td></td>
<td>provisions.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Lack of an agreed description of the term energy poverty and caveats in the</td>
</tr>
<tr>
<td></td>
<td></td>
<td>obligations stand in contrast to the call for action in the Directive.</td>
</tr>
<tr>
<td>EU-added value</td>
<td>Completely</td>
<td>Member States have taken action as a result of EU intervention.</td>
</tr>
</tbody>
</table>

*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, 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 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.

382 "Energy poverty and vulnerable consumers in the energy sector across the EU: analysis of policies and measures". (2015). Insight_E.
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**

<table>
<thead>
<tr>
<th>Energy poverty</th>
<th>Measures</th>
<th>Pros</th>
<th>Cons</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Promoting good practices</td>
<td>Continuous Knowledge exchange.</td>
<td>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.</td>
</tr>
</tbody>
</table>

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) and (e).

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+

<table>
<thead>
<tr>
<th>Measures</th>
<th>Pros</th>
<th>Cons</th>
</tr>
</thead>
<tbody>
<tr>
<td>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.</td>
<td>Stronger enforcement of current legislation and continuous knowledge exchange.</td>
<td>Insufficient to address the shortcomings of the current legislation with regard to energy poverty and targeted protection.</td>
</tr>
</tbody>
</table>

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 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.

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384 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;

385 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;
Table 6: Option 1

<table>
<thead>
<tr>
<th>Measures</th>
<th>Pros</th>
<th>Cons</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy poverty</td>
<td>Generic, adaptable description of the term energy poverty in the legislation. Member States to measure energy poverty.</td>
<td>New legislation will be necessary. Administrative impact on Member States.</td>
</tr>
<tr>
<td></td>
<td>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.</td>
<td></td>
</tr>
</tbody>
</table>

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)\textsuperscript{386}: "... 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)\textsuperscript{387} "...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...”.

- European Parliament (2016)\textsuperscript{388} " 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)\textsuperscript{389} "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\textsuperscript{390} 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**

<table>
<thead>
<tr>
<th>In favour</th>
<th>Against</th>
</tr>
</thead>
<tbody>
<tr>
<td>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.</td>
<td>Limited evidence. Need to compile comparable household data on energy consumption and income to produce reliable statistics.</td>
</tr>
<tr>
<td>Recognition. A common EU-level definition of energy poverty may give the problem better visibility at the Member State level.</td>
<td>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.</td>
</tr>
<tr>
<td>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.</td>
<td>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.</td>
</tr>
</tbody>
</table>

*Source: Thomson et al (2016)*

The Vulnerable Consumers Working Group (VCWG)\textsuperscript{391} 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
- 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 VCGW 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\textsuperscript{392}. 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*


\textsuperscript{392} A few Member States already have a definition of energy poverty. These definitions are presented in Sub-Annex 1.

Addressing 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. 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. However, this indicator has some well-known limitations:

- 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:

- 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.

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394 This kind of indicators is referred in the academic literature as consensual-based indicators.
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.

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

<table>
<thead>
<tr>
<th>Measures</th>
<th>Pros</th>
<th>Cons</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy poverty</td>
<td>- Specific, harmonised definition of energy poverty.</td>
<td>- New legislation will be necessary.</td>
</tr>
<tr>
<td></td>
<td>- Require Member States to measure energy poverty using required energy.</td>
<td>- A prescriptive definition of energy poverty may not be adequate for all Member States.</td>
</tr>
<tr>
<td></td>
<td>- Improve comparability of energy poverty as a result of a harmonised concept of energy poverty.</td>
<td>- High administrative cost to measure energy poverty using required energy.</td>
</tr>
<tr>
<td></td>
<td>- Measuring energy poverty using required energy.</td>
<td></td>
</tr>
<tr>
<td>Safeguards against disconnection</td>
<td>- A minimum notification period before a disconnection.</td>
<td>- New legislation will be necessary.</td>
</tr>
<tr>
<td></td>
<td>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.</td>
<td>- Administrative impact on Member States.</td>
</tr>
<tr>
<td></td>
<td>- Winter moratorium of disconnections for vulnerable consumers.</td>
<td>- Administrative impact on energy companies</td>
</tr>
<tr>
<td></td>
<td>- Equips Member States with the tools to prevent and reduce the number of disconnections.</td>
<td>- Safeguards against disconnection may result in higher costs for companies which may be passed to consumers.</td>
</tr>
<tr>
<td></td>
<td>- Gives customers more time to make arrangements to pay their bills, i.e. avoids unnecessary disconnections and costs of disconnecting and reconnecting.</td>
<td>- 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.</td>
</tr>
<tr>
<td></td>
<td>- Customers are given information about outreach points.</td>
<td>- Moratorium of disconnection may conflict with freedom of contract.</td>
</tr>
<tr>
<td></td>
<td>- Customers are given an opportunity to better handle their energy debts</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- The most vulnerable customers will benefit from a guaranteed energy supply through the coldest months of the year.</td>
<td></td>
</tr>
</tbody>
</table>

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\(^{399}\), 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 a 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\(^{400}\) 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\(^{401}\) 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\(^{402}\) 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.

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\(^{399}\) '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.


\(^{402}\) The UK, which has considerable experience in this field, measures energy poverty or fuel poverty using required energy.
In order to be able to compute required energy, the following information is needed:\(^{403}\):

- heating system and fuels used;
- dwelling characteristics;
- regional and daily climate variations; and
- number of days per year a household stays in their home.

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\(^ {404} \) 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\(^ {405} \).

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>
<thead>
<tr>
<th>Table 9: Statistics on disconnection notices (legal requirements) in Member States</th>
</tr>
</thead>
<tbody>
<tr>
<td>Working days to final disconnection notice(^ {406} )</td>
</tr>
<tr>
<td>--------------------------------------------------</td>
</tr>
<tr>
<td>3</td>
</tr>
<tr>
<td>Working days to actually disconnect a final household customer from the grid because of non-payment</td>
</tr>
</tbody>
</table>

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.

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\(^{403}\) Selecting Indicators to Measure Energy Poverty. 2016. Trinomics.

\(^{404}\) 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.

\(^{405}\) "Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers". Forthcoming publication. Insight_E.

\(^{406}\) Denmark does not stipulate a number of days but rather that a minimum of two notices be sent
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.

**Figure 7: Number of days from which it is cost-effective to disconnect a household**

![Graph showing 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.

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

407 "Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers". Forthcoming publication. Insight_E
projects provide evidence of a link between warmer homes and improvements in health. More information on the benefits of a longer notification period is provided in the next Section.

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.

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Table 10: Additional working days with a two month disconnection notice

<table>
<thead>
<tr>
<th>Member State</th>
<th>Additional number of days</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cyprus</td>
<td>33</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>33</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>30</td>
</tr>
<tr>
<td>Ireland</td>
<td>30</td>
</tr>
<tr>
<td>Malta</td>
<td>26</td>
</tr>
<tr>
<td>Estonia</td>
<td>25</td>
</tr>
<tr>
<td>Lithuania</td>
<td>25</td>
</tr>
<tr>
<td>Portugal</td>
<td>25</td>
</tr>
<tr>
<td>Slovakia</td>
<td>25</td>
</tr>
<tr>
<td>Austria</td>
<td>20</td>
</tr>
<tr>
<td>Slovenia</td>
<td>20</td>
</tr>
<tr>
<td>Sweden</td>
<td>15</td>
</tr>
<tr>
<td>Germany</td>
<td>10</td>
</tr>
<tr>
<td>Italy</td>
<td>10</td>
</tr>
<tr>
<td>Luxembourg</td>
<td>10</td>
</tr>
<tr>
<td>Poland</td>
<td>10</td>
</tr>
<tr>
<td>France</td>
<td>5</td>
</tr>
</tbody>
</table>

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.

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).

---

414 Denmark does not stipulate a number of days but rather that a minimum of two notices be sent
Figure 8: Winter period with ban on disconnection in Member States

<table>
<thead>
<tr>
<th></th>
<th>Sep</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>BELGIUM</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>ESTONIA</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>FINLAND</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>FRANCE</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>HUNGARY</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>IRELAND</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>NETHERLANDS</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>UK</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Costs Description</th>
<th>Quantification</th>
<th>Benefits Description</th>
<th>Quantification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Promoting good practices.</td>
<td>Exchange of good practices and collaboration across Member States</td>
<td>EUR 0.</td>
<td>Continuous Knowledge exchange.</td>
</tr>
</tbody>
</table>

Table 12: Option 0+: costs and benefits

<table>
<thead>
<tr>
<th>Costs Description</th>
<th>Quantification</th>
<th>Benefits Description</th>
<th>Quantification</th>
</tr>
</thead>
<tbody>
<tr>
<td>EU Observatory of Energy Poverty.</td>
<td>Running the EU Observatory of energy poverty.</td>
<td>EUR100,000 per year.</td>
<td>Knowledge exchange.</td>
</tr>
<tr>
<td>NRAs to monitor and report figures on disconnections.</td>
<td>Better implementation of current legislation Electricity Directive Article 37 (j) and (e).</td>
<td>No additional cost.</td>
<td>Improved information on number of disconnections.</td>
</tr>
</tbody>
</table>

Table 13: Policy Option 1: costs and benefits

<table>
<thead>
<tr>
<th>Costs Description</th>
<th>Quantification</th>
<th>Benefits Description</th>
<th>Quantification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy poverty</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generic adaptable description of the term energy poverty in the legislation.</td>
<td>Enumerate the main characteristics that define energy poverty.</td>
<td>No additional cost.</td>
<td>Transparency, clarification and policy synergies.</td>
</tr>
<tr>
<td>Member States to measure energy poverty.</td>
<td>Produce a metric to measure energy poverty.</td>
<td>Administrative cost.</td>
<td>Understanding the extent of the problem. Improved transparency.</td>
</tr>
</tbody>
</table>

Note: Policy Option 1 includes the measures described in option 0+.  

Addressing energy poverty
<table>
<thead>
<tr>
<th>Table 14: Policy Option 2: costs and benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Costs</strong></td>
</tr>
<tr>
<td>Description</td>
</tr>
<tr>
<td><strong>Energy poverty</strong></td>
</tr>
<tr>
<td>Specific definition of energy poverty</td>
</tr>
<tr>
<td>Member States to measure energy poverty using required energy</td>
</tr>
<tr>
<td><strong>Disconnection safeguards</strong></td>
</tr>
<tr>
<td>A minimum notification period before a disconnection.</td>
</tr>
<tr>
<td>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.</td>
</tr>
<tr>
<td>Winter moratorium of disconnections for vulnerable consumers.</td>
</tr>
</tbody>
</table>

*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\textsuperscript{415} using empirical evidence from the academic literature\textsuperscript{416}. 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\textsuperscript{417}. 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.


\textsuperscript{416} Cowell and Gardiner (1999); Pearce and Ulph (1995)

\textsuperscript{417} 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

Exchange of good practices

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

The cost of the EU Observatory of Energy Poverty

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\(^{418}\).

The cost of NRAs monitoring and reporting figures on disconnections

The current energy legislation requires national regulators to monitor disconnections. However, not all Member States report figures on disconnections\(^{419}\). Full implementation of the current legislation represents no extra cost as there is no additional obligation.

Policy Option 1 – calculating the costs

The cost of Member States to measuring energy poverty making reference to household income and household energy expenditure

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\(^{419}\) ACER Market Monitoring Report (2014)
Measuring energy poverty will result in 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\(^2\) 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.

\(^2\) 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

<table>
<thead>
<tr>
<th>Activity</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Identification of information obligations</td>
<td>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.</td>
</tr>
<tr>
<td>Identification of required actions</td>
<td><strong>Familiarising with the information obligation</strong>: senior managers will need to assess the information needed and allocate tasks within the Civil Service to measure energy poverty.</td>
</tr>
<tr>
<td></td>
<td><strong>Training employees about the information obligation</strong>: 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.</td>
</tr>
<tr>
<td></td>
<td><strong>Retrieving relevant information from existing data</strong>: 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.</td>
</tr>
<tr>
<td></td>
<td><strong>Producing new data</strong>: 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.</td>
</tr>
<tr>
<td></td>
<td><strong>Holding meetings</strong>: 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.</td>
</tr>
<tr>
<td></td>
<td><strong>Inspecting and checking</strong>: civil servants will need to perform quality control activities on the data to ensure the robustness of the results.</td>
</tr>
<tr>
<td></td>
<td><strong>Submitting the information</strong>: 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.</td>
</tr>
<tr>
<td>Identification of target group</td>
<td>Public Authorities</td>
</tr>
<tr>
<td>Identification of frequency of required actions</td>
<td>Once a year</td>
</tr>
<tr>
<td>Identification of relevant cost parameters</td>
<td>No particular relevant cost such as external costs (e.g. using consultancies or gathering new data) has been identified.</td>
</tr>
<tr>
<td>Assessment of the number of entities concerned</td>
<td>28 Member States</td>
</tr>
</tbody>
</table>

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

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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)

<table>
<thead>
<tr>
<th></th>
<th>First year</th>
<th>Following years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standard Cost Model</td>
<td>EUR 454,129</td>
<td>EUR 255,277</td>
</tr>
<tr>
<td>Estimated cost in France, UK, Ireland</td>
<td>(-EUR 57,137)</td>
<td>(-EUR 32,444)</td>
</tr>
<tr>
<td>Estimated cost in Croatia</td>
<td>EUR 10383</td>
<td>EUR 5788</td>
</tr>
<tr>
<td>Final cost</td>
<td>EUR 407,375</td>
<td>EUR 228,621</td>
</tr>
</tbody>
</table>

*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

<table>
<thead>
<tr>
<th>Obligation</th>
<th>Action</th>
<th>Target Group</th>
<th>Staff type</th>
<th>Hourly rate</th>
<th>Man hours</th>
<th>Activity cost (EUR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measuring energy poverty</td>
<td>Familiarizing with the information obligation</td>
<td>28 MS</td>
<td>Legislators, senior officials and managers</td>
<td>41.5</td>
<td>65</td>
<td>75,530</td>
</tr>
<tr>
<td></td>
<td>Training employees about the information obligations</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>33</td>
<td>29,660</td>
</tr>
<tr>
<td></td>
<td>Retrieving relevant information from existing data</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>50</td>
<td>44,491</td>
</tr>
<tr>
<td></td>
<td>Adjusting existing data</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>25</td>
<td>22,470</td>
</tr>
<tr>
<td></td>
<td>Producing new data</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>143</td>
<td>128,079</td>
</tr>
<tr>
<td></td>
<td>Holding meetings</td>
<td>28 MS</td>
<td>Legislators, senior officials and managers</td>
<td>41.5</td>
<td>52</td>
<td>60,424</td>
</tr>
<tr>
<td></td>
<td>Inspecting and checking</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>31</td>
<td>27,638</td>
</tr>
<tr>
<td></td>
<td>Copying</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>50</td>
<td>44,940</td>
</tr>
<tr>
<td></td>
<td>Submitting the information</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>23</td>
<td>20,897</td>
</tr>
</tbody>
</table>

*Source: European Commission’s calculation*
## Table 18: Administrative costs of measuring energy poverty in following years

<table>
<thead>
<tr>
<th>Obligation</th>
<th>Action</th>
<th>Target Group</th>
<th>Staff type</th>
<th>Hourly rate</th>
<th>Man hours</th>
<th>Activity cost (EUR)</th>
<th>cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measuring energy poverty</td>
<td>Familiarizing with the information obligation</td>
<td>28 MS</td>
<td>Legislators, senior officials and managers</td>
<td>41.5</td>
<td>27</td>
<td>31,374</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Training employees about the information obligations</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>29</td>
<td>26,065</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Retrieving relevant information from existing data</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>33</td>
<td>29,660</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Adjusting existing data</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>12.5</td>
<td>11,235</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Producing new data</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>45</td>
<td>40,446</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Holding meetings</td>
<td>28 MS</td>
<td>Legislators, senior officials and managers</td>
<td>41.5</td>
<td>26</td>
<td>30,212</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Inspecting and checking</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>33</td>
<td>29,660</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Copying</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>45</td>
<td>40,446</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Submitting the information</td>
<td>28 MS</td>
<td>Professionals</td>
<td>32.1</td>
<td>18</td>
<td>16,178</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>Total</strong></td>
<td>255,277</td>
</tr>
</tbody>
</table>

*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 (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 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, making the physical survey the main additional cost of this measure.

Table 19: SHCS – cost structure

<table>
<thead>
<tr>
<th>SHCS – Activities</th>
<th>Description of activities</th>
<th>SHCS – Share of total cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Survey management</td>
<td>Project management, recruitment, briefing and training, etc.</td>
<td>15%</td>
</tr>
<tr>
<td>Fieldwork costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Social surveys</td>
<td>45 minutes social interview and 60 minutes physical survey, and work to secure interviews.</td>
<td>24%</td>
</tr>
<tr>
<td>- Physical survey</td>
<td></td>
<td>33%</td>
</tr>
<tr>
<td>Processes and final</td>
<td>Data processing, sampling, selection, questionnaire development, validation, clean datasets, and survey reports.</td>
<td>24%</td>
</tr>
<tr>
<td>output</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Estimating energy</td>
<td>Energy poverty modelling using information collected in the surveys</td>
<td>4%</td>
</tr>
<tr>
<td>poverty</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*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:

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424 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\textsuperscript{425} provided by Eurostat.

Table 20: Cost per dwelling adjusted by Member States labour costs

<table>
<thead>
<tr>
<th>Member State</th>
<th>Adjustment factor (MS’ labour cost / UK labour cost – category: professional)</th>
<th>Cost per interview (EUR)</th>
<th>Sample size required</th>
<th>Total cost (EUR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BE</td>
<td>1.3</td>
<td>346</td>
<td>3,459</td>
<td>1,195,000</td>
</tr>
<tr>
<td>BG</td>
<td>0.1</td>
<td>27</td>
<td>1,343</td>
<td>36,000</td>
</tr>
<tr>
<td>CZ</td>
<td>0.3</td>
<td>82</td>
<td>3,182</td>
<td>262,000</td>
</tr>
<tr>
<td>DK</td>
<td>1.2</td>
<td>320</td>
<td>1,697</td>
<td>544,000</td>
</tr>
<tr>
<td>DE</td>
<td>1.1</td>
<td>298</td>
<td>37,606</td>
<td>11,209,000</td>
</tr>
<tr>
<td>ET</td>
<td>0.2</td>
<td>62</td>
<td>1,619</td>
<td>100,000</td>
</tr>
<tr>
<td>IE</td>
<td>1.1</td>
<td>291</td>
<td>2,562</td>
<td>746,000</td>
</tr>
<tr>
<td>EL</td>
<td>0.7</td>
<td>184</td>
<td>1,512</td>
<td>278,000</td>
</tr>
<tr>
<td>ES</td>
<td>0.7</td>
<td>193</td>
<td>8,743</td>
<td>1,688,000</td>
</tr>
<tr>
<td>FR</td>
<td>1.0</td>
<td>274</td>
<td>5,114</td>
<td>1,404,000</td>
</tr>
<tr>
<td>IT</td>
<td>1.0</td>
<td>272</td>
<td>8,884</td>
<td>2,420,000</td>
</tr>
<tr>
<td>CY</td>
<td>0.8</td>
<td>219</td>
<td>1,910</td>
<td>419,000</td>
</tr>
<tr>
<td>LV</td>
<td>0.2</td>
<td>44</td>
<td>1,653</td>
<td>73,000</td>
</tr>
<tr>
<td>LT</td>
<td>0.2</td>
<td>44</td>
<td>1,242</td>
<td>55,000</td>
</tr>
<tr>
<td>LU</td>
<td>1.3</td>
<td>356</td>
<td>3,068</td>
<td>1,092,000</td>
</tr>
<tr>
<td>HU</td>
<td>0.2</td>
<td>60</td>
<td>4,175</td>
<td>250,000</td>
</tr>
<tr>
<td>MT</td>
<td>0.4</td>
<td>116</td>
<td>3,157</td>
<td>366,000</td>
</tr>
<tr>
<td>NL</td>
<td>0.9</td>
<td>249</td>
<td>1,461</td>
<td>364,000</td>
</tr>
<tr>
<td>AT</td>
<td>1.0</td>
<td>269</td>
<td>2,962</td>
<td>796,000</td>
</tr>
<tr>
<td>PL</td>
<td>0.3</td>
<td>91</td>
<td>4,022</td>
<td>367,000</td>
</tr>
<tr>
<td>PO</td>
<td>0.6</td>
<td>156</td>
<td>30,228</td>
<td>4,708,000</td>
</tr>
<tr>
<td>RO</td>
<td>0.2</td>
<td>45</td>
<td>6,328</td>
<td>288,000</td>
</tr>
<tr>
<td>SL</td>
<td>0.5</td>
<td>138</td>
<td>2,658</td>
<td>366,000</td>
</tr>
<tr>
<td>SK</td>
<td>0.3</td>
<td>69</td>
<td>2,076</td>
<td>143,000</td>
</tr>
<tr>
<td>FI</td>
<td>0.9</td>
<td>253</td>
<td>2,532</td>
<td>640,000</td>
</tr>
<tr>
<td>SE</td>
<td>1.0</td>
<td>258</td>
<td>2,157</td>
<td>556,000</td>
</tr>
<tr>
<td>HR</td>
<td>0.5</td>
<td>138</td>
<td>2,464</td>
<td>340,000</td>
</tr>
<tr>
<td>Total Cost</td>
<td></td>
<td></td>
<td></td>
<td>30,704,000</td>
</tr>
</tbody>
</table>

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. 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

426 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 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.

---

427 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

<table>
<thead>
<tr>
<th>Member State</th>
<th>Central Cost (10%) in EUR</th>
<th>High Cost (30%) in EUR</th>
</tr>
</thead>
<tbody>
<tr>
<td>AT</td>
<td>148,160</td>
<td>1,027,465</td>
</tr>
<tr>
<td>BG*</td>
<td>184,081</td>
<td>624,502</td>
</tr>
<tr>
<td>CY</td>
<td>236,164</td>
<td>942,264</td>
</tr>
<tr>
<td>CZ*</td>
<td>405,482</td>
<td>1,587,838</td>
</tr>
<tr>
<td>DE</td>
<td>627,268</td>
<td>9,340,006</td>
</tr>
<tr>
<td>DK</td>
<td>219,079</td>
<td>1,216,659</td>
</tr>
<tr>
<td>EE*</td>
<td>-5,018</td>
<td>96,725</td>
</tr>
<tr>
<td>FR</td>
<td>1,617,788</td>
<td>6,439,202</td>
</tr>
<tr>
<td>IE</td>
<td>35,596</td>
<td>222,339</td>
</tr>
<tr>
<td>IT</td>
<td>-570,068</td>
<td>18,342,145</td>
</tr>
<tr>
<td>LT</td>
<td>6,046</td>
<td>24,428</td>
</tr>
<tr>
<td>LU*</td>
<td>3,194</td>
<td>24,311</td>
</tr>
<tr>
<td>MT</td>
<td>11,103</td>
<td>47,098</td>
</tr>
<tr>
<td>PL</td>
<td>945,689</td>
<td>4,131,371</td>
</tr>
<tr>
<td>PT</td>
<td>2,328,274</td>
<td>9,210,831</td>
</tr>
<tr>
<td>SE*</td>
<td>156,570</td>
<td>778,667</td>
</tr>
<tr>
<td>SI*</td>
<td>204,133</td>
<td>708,164</td>
</tr>
<tr>
<td>SK</td>
<td>109,395</td>
<td>484,050</td>
</tr>
<tr>
<td><strong>Total Annual Cost</strong></td>
<td><strong>6,662,934</strong></td>
<td><strong>55,248,063</strong></td>
</tr>
</tbody>
</table>

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.

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.

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, 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.

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.

428 "Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers". Forthcoming publication. Insight_E
429 "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. 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. A similar scheme operates in Germany at the local level. 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 2. 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 – 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

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430 Step Change: http://www.stepchange.org/
431 2014 average exchange rate of GBP 0.806 for one euro.
432 Information on the scheme can be found at: https://www.verbraucherzentrale.nrw/mediabig/238730A.pdf and https://www.verbraucherzentrale.nrw/mediabig/237456A.pdf
433 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

<table>
<thead>
<tr>
<th>Member State</th>
<th>Estimated cost of debt management (EUR)</th>
<th>Member State</th>
<th>Estimated cost of customer engagement (EUR)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Central Cost</td>
<td>High Cost</td>
<td>Central Cost</td>
</tr>
<tr>
<td>BG</td>
<td>114,408</td>
<td>6,770,270</td>
<td>BG</td>
</tr>
<tr>
<td>DK</td>
<td>7,665,949</td>
<td>73,559,897</td>
<td>CY</td>
</tr>
<tr>
<td>EE</td>
<td>65,607</td>
<td>3,882,393</td>
<td>CZ</td>
</tr>
<tr>
<td>FI</td>
<td>708,564</td>
<td>41,930,412</td>
<td>EE</td>
</tr>
<tr>
<td>HR</td>
<td>1,016,791</td>
<td>22,934,923</td>
<td>FI</td>
</tr>
<tr>
<td>LT</td>
<td>95,899</td>
<td>5,634,449</td>
<td>GR</td>
</tr>
<tr>
<td>LV</td>
<td>22,088</td>
<td>1,266,903</td>
<td>HR</td>
</tr>
<tr>
<td>PT</td>
<td>33,574,204</td>
<td>91,806,810</td>
<td>HU</td>
</tr>
<tr>
<td>RO</td>
<td>293,008</td>
<td>17,339,207</td>
<td>LT</td>
</tr>
<tr>
<td>SK</td>
<td>121,024</td>
<td>7,161,768</td>
<td>LV</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>MT</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>NL</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>SI</td>
</tr>
<tr>
<td><strong>Total Annual Cost</strong></td>
<td>43,677,542</td>
<td>272,287,031</td>
<td><strong>Total Annual Cost</strong></td>
</tr>
</tbody>
</table>

*Note: the number of reported disconnections in the Netherlands was nil. CEER database*  
*Source: European Commission’s calculation*

#### The cost of disconnection safeguards - winter moratorium of disconnections for vulnerable consumers.

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

<table>
<thead>
<tr>
<th>Member state</th>
<th>Vulnerable consumers</th>
<th>Electricity</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Central cost case (10% disconnect and never pays back) in EUR</td>
<td>High cost case (30% disconnect and never pays back) in EUR</td>
</tr>
<tr>
<td>AT*</td>
<td>118,357</td>
<td>2,092,547</td>
<td>6,277,640</td>
</tr>
<tr>
<td>BG*</td>
<td>1,048,035</td>
<td>9,643,610</td>
<td>28,930,829</td>
</tr>
<tr>
<td>CZ*</td>
<td>267,191</td>
<td>4,559,591</td>
<td>13,678,772</td>
</tr>
<tr>
<td>DE*</td>
<td>1,978,803</td>
<td>33,507,728</td>
<td>100,523,184</td>
</tr>
<tr>
<td>LU*</td>
<td>1,374</td>
<td>26,642</td>
<td>79,926</td>
</tr>
<tr>
<td>LV*</td>
<td>215,001</td>
<td>1,743,136</td>
<td>5,229,408</td>
</tr>
<tr>
<td>MT</td>
<td>24,416</td>
<td>242,927</td>
<td>728,782</td>
</tr>
<tr>
<td>PT</td>
<td>61,129</td>
<td>941,387</td>
<td>2,824,160</td>
</tr>
<tr>
<td>SK*</td>
<td>117,990</td>
<td>1,172,983</td>
<td>3,518,950</td>
</tr>
<tr>
<td>Total Annual Cost</td>
<td>53,930,551</td>
<td>161,791,651</td>
<td>22,439,374</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Policy Option</th>
<th>Annual cost in EUR</th>
<th>Net present cost for the period 2020 – 2030 in EUR</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU: sharing of good practices.</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Option 0+: sharing of good practices and increasing the efforts to correctly implement the legislation.</td>
<td>100,000</td>
<td>911,090</td>
</tr>
</tbody>
</table>

**Policy Option 1:** Setting an EU framework to monitor energy poverty

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Central cost scenario</th>
<th>407,375 (first year)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>228,621 (following years)</td>
<td>2,261,696</td>
</tr>
</tbody>
</table>

**Policy Option 2:** Setting a uniform EU framework to monitor energy poverty, preventative measures to avoid disconnections and disconnection winter moratorium for vulnerable consumers.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Central cost scenario</th>
<th>159,105,345</th>
<th>1,194,481,728</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>High cost scenario</td>
<td>587,348,869</td>
<td>3,820,183,393</td>
</tr>
</tbody>
</table>

Source: European Commission’s calculation

Addressing energy poverty
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 homes⁴³⁴. The 2009 Annual Report of the Chief Medical Officers⁴³⁵ 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 productive⁴³⁶. 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 Europe⁴³⁷⁴³⁸⁴³⁹. 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 children⁴⁴⁰.

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⁴³⁴ "Indoor cold and mortality. In Environmental Burden of Disease Associated with Inadequate Housing", (Bonn: World Health Organisation (Regional office for Europe)). (2011). Rudge, J.
⁴³⁶ "Healthy Homes Barometer", (2016). Wegener and Fedkenheuer,
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

The benefits of a generic description of the term energy poverty in the legislation

Three main benefits have been identified as a result of a shared understanding of energy poverty across the EU: recognition, clarification and policy synergy.441

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 households across Europe are struggling to access adequate energy services.442

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

energy poverty is mixed or used interchangeably with the broader term of consumer vulnerability or general poverty⁴⁴³. 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.

The benefits of measuring energy poverty by referring to household income and household energy expenditure

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 policies⁴⁴⁴.

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

The benefits of a specific EU definition of energy poverty

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 dependency⁴⁴⁵.

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\(^{446}\). It requires, nonetheless, agreeing on what is adequate. In some cases, the term adequate refers to a specific heating regime\(^{447}\).

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


\(^{447}\) 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](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\textsuperscript{448} by the GDP per capita\textsuperscript{449}
- Calculate the reduction in EWD that equals the cost of the policies.

The results of the calculation are presented below.

Table 25: Sensitivity analysis

<table>
<thead>
<tr>
<th>Policy Option 1: Setting an EU framework to monitor energy poverty</th>
<th>Benefits from reduction in Excess Winter Deaths equal to the cost of the policies</th>
</tr>
</thead>
<tbody>
<tr>
<td>Policy Option 1 – first year</td>
<td>0.004%</td>
</tr>
<tr>
<td>Policy Option 1 – following years</td>
<td>0.002%</td>
</tr>
<tr>
<td>Policy Option 2: Setting an EU uniform framework to monitor energy poverty and reduce disconnections for vulnerable consumers.</td>
<td></td>
</tr>
<tr>
<td>Policy Option 2 – central cost scenario</td>
<td>1.5%</td>
</tr>
<tr>
<td>Policy Option 2 – high cost scenario</td>
<td>5.6%</td>
</tr>
</tbody>
</table>

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

\textsuperscript{448} 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.

\textsuperscript{449} Eurostat. GDP per capita in euros at current prices.
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 of the Treaty of 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 VCGW 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 VCGW 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>
<thead>
<tr>
<th>Organisation</th>
<th>Member State</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ministry of Economics</td>
<td>Latvia</td>
</tr>
<tr>
<td>Ministry of Economy</td>
<td>Poland</td>
</tr>
<tr>
<td>Ministry of Employment and the Economy, Energy Department</td>
<td>Finland</td>
</tr>
<tr>
<td>Ministry of National Development</td>
<td>Hungary</td>
</tr>
<tr>
<td>Bulgarian Permanent Representation to the EU</td>
<td>Bulgaria</td>
</tr>
<tr>
<td>Hungarian Permanent Representation to the EU</td>
<td>Hungary</td>
</tr>
<tr>
<td>Czech Permanent Representation to the EU</td>
<td>Czech Republic</td>
</tr>
<tr>
<td>FPS Economy - DG Energy</td>
<td>Belgium</td>
</tr>
<tr>
<td>ERO - Energy Regulatory Office of the Czech Republic</td>
<td>Czech Republic</td>
</tr>
<tr>
<td>E-control Austrian Energy Regulator</td>
<td>Austria</td>
</tr>
<tr>
<td>OFGEM</td>
<td>United Kingdom</td>
</tr>
<tr>
<td>NEON</td>
<td>European Organisation</td>
</tr>
<tr>
<td>Citizens advice</td>
<td>United Kingdom</td>
</tr>
<tr>
<td>Danish Consumer Council</td>
<td>Denmark</td>
</tr>
<tr>
<td>DECO</td>
<td>Portugal</td>
</tr>
<tr>
<td>The Swedish Consumer Energy Markets Bureau</td>
<td>Sweden</td>
</tr>
<tr>
<td>RWADE</td>
<td>Belgium</td>
</tr>
<tr>
<td>University of Leicester</td>
<td>United Kingdom</td>
</tr>
<tr>
<td>University of Stuttgart</td>
<td>Germany</td>
</tr>
<tr>
<td>European Disability Forum</td>
<td>European Organisation</td>
</tr>
<tr>
<td>Fondazione Consumo Sostenibile</td>
<td>Italy</td>
</tr>
<tr>
<td>GEODE</td>
<td>European Organisation</td>
</tr>
<tr>
<td>HISPACOOP</td>
<td>Spain</td>
</tr>
<tr>
<td>Housing Europe</td>
<td>Belgium</td>
</tr>
<tr>
<td>International Union of Tenants</td>
<td>European Organisation</td>
</tr>
<tr>
<td>EURELECTRIC</td>
<td>European Organisation</td>
</tr>
<tr>
<td>EUROGAS</td>
<td>European Organisation</td>
</tr>
<tr>
<td>ADEME</td>
<td>France</td>
</tr>
<tr>
<td>AEEGSI</td>
<td>Italy</td>
</tr>
<tr>
<td>AISFOR</td>
<td>Italy</td>
</tr>
<tr>
<td>CEDEC</td>
<td>European Organisation</td>
</tr>
<tr>
<td>DGEC</td>
<td>France</td>
</tr>
<tr>
<td>EAPN</td>
<td>European organisation</td>
</tr>
<tr>
<td>EFIEES</td>
<td>European Organisation</td>
</tr>
<tr>
<td>ENGIE</td>
<td>France</td>
</tr>
<tr>
<td>FdSS</td>
<td>France</td>
</tr>
</tbody>
</table>

In the meetings of the VCWG\textsuperscript{450}, the group discussed the topic of energy poverty. These discussions were captured in the Working Paper on Energy Poverty\textsuperscript{451}. 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

\textsuperscript{450} The minutes, agenda and presentations of the meetings can be found online at: https://ec.europa.eu/energy/en/events/citizens-energy-forum-london

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.
### Table 27: Energy poverty definitions

<table>
<thead>
<tr>
<th>Member State</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>France</td>
<td>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.</td>
</tr>
<tr>
<td>Ireland</td>
<td>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.</td>
</tr>
<tr>
<td>Cyprus</td>
<td>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.</td>
</tr>
<tr>
<td>Slovakia</td>
<td>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”</td>
</tr>
<tr>
<td>England</td>
<td>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.</td>
</tr>
<tr>
<td>Scotland</td>
<td>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.</td>
</tr>
<tr>
<td>Wales</td>
<td>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.</td>
</tr>
<tr>
<td>Northern Ireland</td>
<td>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.</td>
</tr>
</tbody>
</table>

*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**

<table>
<thead>
<tr>
<th>Option: 0</th>
<th>Option 1</th>
<th>Option 2a</th>
<th>Option 2b</th>
</tr>
</thead>
<tbody>
<tr>
<td>Making use of existing <em>acquis</em> 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.</td>
<td>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).</td>
<td>Requiring Member States to progressively phase-out below cost price regulation for households by a deadline specified in new EU legislation, starting with prices below costs, for households above a certain consumption threshold to be defined in new EU legislation or by Member States.</td>
<td>Requiring Member States to progressively phase-out below cost price regulation for households by a deadline specified in new EU legislation.</td>
</tr>
</tbody>
</table>

**Pros:**
- Allows a case-by-case assessment of the proportionality of price regulation, taking into account social and economic particularities in Member States
- Ensures regulatory predictability and transparency for supply activities across the EU.

**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.

**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.

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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\(^ {453}\) 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\(^ {454}\) 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).

\(^ {453}\) Case C-265/08, Federutility and others v Autorità per l’energia elettrica e il gas

\(^ {454}\) 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)\textsuperscript{455}. 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.

\textsuperscript{455} 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).
Table 1: Energy price regulation in EU Member States – February 2016

<table>
<thead>
<tr>
<th>Member State</th>
<th>Electricity</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Bulgaria</strong></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td><strong>Croatia</strong></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td><strong>Cyprus</strong></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Czech Republic</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Denmark&lt;sup&gt;a&lt;/sup&gt;</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Estonia</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Finland</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>France</strong></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Germany</td>
<td></td>
<td></td>
</tr>
<tr>
<td>UK (Great Britain)</td>
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<td></td>
</tr>
<tr>
<td>UK (Northern Ireland)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td><strong>Greece</strong>&lt;sup&gt;ii&lt;/sup&gt;</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Hungary</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Ireland</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Italy</strong>&lt;sup&gt;iii&lt;/sup&gt;</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td><strong>Latvia</strong>&lt;sup&gt;v&lt;/sup&gt;</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Lithuania&lt;sup&gt;vi&lt;/sup&gt;</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Luxembourg</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Malta</strong>&lt;sup&gt;vii&lt;/sup&gt;</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Netherlands</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Poland</strong>&lt;sup&gt;iii&lt;/sup&gt;</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td><strong>Portugal</strong>&lt;sup&gt;iv&lt;/sup&gt;</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Romania&lt;sup&gt;v&lt;/sup&gt;</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Slovakia</td>
<td>X</td>
<td>X</td>
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<tr>
<td>Slovenia</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Spain</strong>&lt;sup&gt;vi&lt;/sup&gt;</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Sweden</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: European Commission Data.

- Price regulation economically justified due to natural monopoly.
- <sup>a</sup> **Denmark** is implementing measures aimed at progressively removing regulated prices. This follows from changes in the energy law introduced in January 2013.
- <sup>ii</sup> 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.
- <sup>iii</sup> **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.
- <sup>v</sup> **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.
- <sup>vi</sup> **Lithuania** has removed electricity regulated prices in the beginning of 2015.
- <sup>vii</sup> **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.
- <sup>viii</sup> 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.

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<sup>456</sup> Based on current state of play of the conformity checks.

Phasing out regulated prices
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.

Romania has agreed an electricity and gas price deregulation calendar as part of the Economic Adjustment Programme.

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.
Phasing out 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
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.
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**

![Figure 1: Different components of the final electricity price](image)

*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. In addition, it is also argued that customers are reluctant to change and in some cases inability to make appropriate choices.

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

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459 “Retail competition in electricity markets” (2009) Christophe Defeuilley
precisely the activity that can lead to products that best suit customers' preferences. Based on the US experience with energy market liberalisation Zarnikau and Whitworth, Rose and Joskow 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.

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.

460 "Retail competition in electricity markets—expectations, outcomes and Economics" (2009) Stephen Littlechild
464 "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
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.
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. Data from the Agency for the Cooperation of Energy Regulators (ACER) shows that Member States without regulated prices have on average slightly higher energy prices.

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Phasing out regulated prices
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. 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>
<thead>
<tr>
<th>Cumulated tariff debt, % of GDP, 2013</th>
<th>ES</th>
<th>PT</th>
<th>EL</th>
<th>FR</th>
<th>IT</th>
<th>DE</th>
<th>BG</th>
<th>MT</th>
<th>RO</th>
<th>HU</th>
<th>LV</th>
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</thead>
<tbody>
<tr>
<td>Fractions within countries</td>
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<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- on RES account</td>
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<td>✓</td>
<td>✓</td>
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<td>✓</td>
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</tr>
<tr>
<td>- on PSO account</td>
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<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
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<td>✓</td>
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</tr>
<tr>
<td>Scope of the tariff deficit</td>
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<td></td>
<td></td>
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<td></td>
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<tr>
<td>- of access costs</td>
<td>✓</td>
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<td>✓</td>
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</tr>
<tr>
<td>- of integral tariff</td>
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<td>✓</td>
<td>✓</td>
<td>✓</td>
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</tr>
<tr>
<td>- tariff below costs</td>
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<td>✓</td>
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<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Deficit recognized by the authorities or energy regulator?</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Deficit cumulative (i.e. not settled in the following period)</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
</tbody>
</table>

* 2012. ** World Bank forecast

Source: Commission Services

Source: DG ECFIN, European Commission

"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.\footnote{468} 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.\footnote{469}

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

\footnote{468} "The impact of oil price on EU energy prices" (2014) European Parliament
\footnote{469} "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

<table>
<thead>
<tr>
<th>Country</th>
<th>Min_2 / Max_2</th>
<th>Q_2</th>
<th>Q_3</th>
<th>Q_4</th>
<th>Q_5</th>
<th>Total</th>
<th>Share [Q2/Q5]</th>
<th>Share [Q5]</th>
</tr>
</thead>
<tbody>
<tr>
<td>BG</td>
<td>1.8181</td>
<td>1.9771</td>
<td>2.0471</td>
<td>2.3799</td>
<td>2.3553</td>
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<td>0.7090</td>
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<td>0.8544</td>
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<td>LU</td>
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<tr>
<td>LV</td>
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<td>0.3211</td>
<td>0.3400</td>
<td>0.5103</td>
<td>0.4900</td>
<td>1.199302282</td>
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<td>9.8904</td>
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<td>13.053</td>
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<td>1.7283</td>
<td>1.9068</td>
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</tr>
<tr>
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<td>32.7540</td>
<td>133.427213</td>
<td>65.31</td>
<td>24.54</td>
</tr>
</tbody>
</table>

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.
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.
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

<table>
<thead>
<tr>
<th>Country</th>
<th>Number of electricity only offers</th>
<th>Dual-fuel available</th>
<th>Certified green energy offers available</th>
<th>Availability of non-price financial benefits</th>
<th>ICT offer</th>
<th>Variety of energy pricing alternatives available to consumers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>53</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
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<td></td>
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<tr>
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<td></td>
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<td>Yes</td>
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<td>Yes</td>
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<td></td>
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<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>

*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**

![Customer external switching rates](image)

*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)**

![Proportion of customers who have never switched contract](image)

*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

![Savings on incumbent (%)](chart)

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 retailers 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**

![Market Performance Indicator](image)

*Source: EC, DG JUST*[^70]

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.

[^70]: "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

![Graph showing market performance indicator](image)

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

![Graph showing customer satisfaction](image)

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

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Scope</th>
<th>Low score = 0</th>
<th>High score =10</th>
<th>Weight</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concentration ratio, CR3</td>
<td>National</td>
<td>Market share of three largest suppliers 100%</td>
<td>Market share of three largest suppliers 30% or less</td>
<td>10</td>
</tr>
<tr>
<td>Number of suppliers with market share &gt; 5%</td>
<td>National</td>
<td>Low number of suppliers</td>
<td>High number of suppliers</td>
<td>10</td>
</tr>
<tr>
<td>Ability to compare prices easily</td>
<td>National</td>
<td>Difficult to compare prices</td>
<td>Easy to compare prices</td>
<td>10</td>
</tr>
<tr>
<td>Average net entry (2012-2014)</td>
<td>National</td>
<td>Net entry zero</td>
<td>Net entry of five or more nationwide suppliers</td>
<td>10</td>
</tr>
<tr>
<td>Switching rates (supplier + tariff switching) over 2010-2014</td>
<td>National</td>
<td>Annual switching rate zero</td>
<td>Annual switching rate 20% or more</td>
<td>10</td>
</tr>
<tr>
<td>Non-switchers</td>
<td>National</td>
<td>None have switched</td>
<td>All have &lt;1/3 not switched</td>
<td>10</td>
</tr>
<tr>
<td>Number of offers per supplier</td>
<td>Capital city</td>
<td>One offer per supplier</td>
<td>Five or more offers per supplier</td>
<td>10</td>
</tr>
<tr>
<td>Does the market meet expectations</td>
<td>National</td>
<td>Market does not meet expectations</td>
<td>Market fully meets expectations</td>
<td>10</td>
</tr>
<tr>
<td>Average mark-up (2012–2014) adjusted for proportion of consumers on non-regulated prices</td>
<td>National</td>
<td>High mark-up</td>
<td>Low mark-up</td>
<td>10</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Time limitation</th>
<th>0. Non legislative: Making use of existing acquis to continue bilateral consultations and enforcement actions, accompanied by EU guidance</th>
<th>1. Legislative obligation: No price regulation but social tariffs allowed</th>
<th>2a. Legislative obligation: Price regulation allowed below certain consumption threshold</th>
<th>2b. Legislative obligation: Cost covering price regulation allowed without limitation as to the amount of energy consumed</th>
</tr>
</thead>
<tbody>
<tr>
<td>End date to be set by each Member State in compliance with EU acquis to be assessed on case-by-case basis.</td>
<td>End date set in EU legislation for all price regulation (except social tariffs)</td>
<td>End date set in EU legislation for price regulation above a certain consumption threshold. No end date for price regulation below the defined threshold.</td>
<td>End date set in EU legislation for price regulation below costs No end date for price regulation below the defined threshold.</td>
<td></td>
</tr>
<tr>
<td>Limitation as to the scope of beneficiaries</td>
<td>Scope of beneficiaries to be defined by each Member State in compliance with EU acquis to be assessed on case-by-case basis.</td>
<td>No beneficiaries of price regulation. Social tariffs allowed as transitional measure.</td>
<td>Beneficiaries of price regulation limited to households below a certain consumption threshold.</td>
<td>No limitation as regards the scope of beneficiaries (all households).</td>
</tr>
<tr>
<td>Methodology for setting the price</td>
<td>Methodology to be defined by each Member State in compliance with EU acquis to be assessed on case-by-case basis.</td>
<td>No provisions as regards methodology (cost coverage etc.) necessary as all price regulation is to be phased out.</td>
<td>Methodology to be defined by each Member State in compliance with EU acquis to be assessed on case-by-case basis.</td>
<td>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.</td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>Member State</th>
<th>Average annual electricity consumption kWh/HH</th>
<th>Average annual expenditure on electricity EURO/HH</th>
</tr>
</thead>
<tbody>
<tr>
<td>BG</td>
<td>3836</td>
<td>275</td>
</tr>
<tr>
<td>CY</td>
<td>4935</td>
<td>920</td>
</tr>
<tr>
<td>DK</td>
<td>4288</td>
<td>439</td>
</tr>
<tr>
<td>ES</td>
<td>3855</td>
<td>687</td>
</tr>
<tr>
<td>FR</td>
<td>5204</td>
<td>499</td>
</tr>
<tr>
<td>GR</td>
<td>3953</td>
<td>471</td>
</tr>
<tr>
<td>HR</td>
<td>3712</td>
<td>374</td>
</tr>
<tr>
<td>HU</td>
<td>2522</td>
<td>233</td>
</tr>
<tr>
<td>IT</td>
<td>2494</td>
<td>375</td>
</tr>
<tr>
<td>LT</td>
<td>2025</td>
<td>180</td>
</tr>
<tr>
<td>LV</td>
<td>2099</td>
<td>180</td>
</tr>
<tr>
<td>MT</td>
<td>4266</td>
<td>553</td>
</tr>
<tr>
<td>PL</td>
<td>2010</td>
<td>221</td>
</tr>
<tr>
<td>PT</td>
<td>2935</td>
<td>377</td>
</tr>
<tr>
<td>RO</td>
<td>1590</td>
<td>144</td>
</tr>
<tr>
<td>SK</td>
<td>2682</td>
<td>330</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th></th>
<th>A - Financing across all non-vulnerable households</th>
<th>B - Financing across all households</th>
<th>C - Financing across all electricity consumers</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Non-vulnerable Households (regular tariff)</td>
<td>Vulnerable Households (social tariff)</td>
<td>Non-vulnerable Households (regular tariff)</td>
</tr>
<tr>
<td>BG</td>
<td>14%</td>
<td>-20%</td>
<td>8%</td>
</tr>
<tr>
<td>CY</td>
<td>8%</td>
<td>-20%</td>
<td>6%</td>
</tr>
<tr>
<td>DK</td>
<td>1%</td>
<td>-20%</td>
<td>1%</td>
</tr>
<tr>
<td>ES</td>
<td>2%</td>
<td>-20%</td>
<td>2%</td>
</tr>
<tr>
<td>FR</td>
<td>1%</td>
<td>-20%</td>
<td>1%</td>
</tr>
<tr>
<td>GR</td>
<td>10%</td>
<td>-20%</td>
<td>7%</td>
</tr>
<tr>
<td>HR</td>
<td>2%</td>
<td>-20%</td>
<td>2%</td>
</tr>
<tr>
<td>HU</td>
<td>3%</td>
<td>-20%</td>
<td>2%</td>
</tr>
<tr>
<td>IT</td>
<td>4%</td>
<td>-20%</td>
<td>4%</td>
</tr>
<tr>
<td>LT</td>
<td>7%</td>
<td>-20%</td>
<td>5%</td>
</tr>
<tr>
<td>LV</td>
<td>4%</td>
<td>-20%</td>
<td>3%</td>
</tr>
<tr>
<td>MT</td>
<td>6%</td>
<td>-20%</td>
<td>4%</td>
</tr>
<tr>
<td>PL</td>
<td>2%</td>
<td>-20%</td>
<td>2%</td>
</tr>
<tr>
<td>PT</td>
<td>8%</td>
<td>-20%</td>
<td>6%</td>
</tr>
<tr>
<td>RO</td>
<td>3%</td>
<td>-20%</td>
<td>2%</td>
</tr>
</tbody>
</table>

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)
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**

<table>
<thead>
<tr>
<th>Measure</th>
<th>Costs Description</th>
<th>Quantification</th>
<th>Benefits Description</th>
<th>Quantification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Targeted price regulation for vulnerable customers in the form of social tariffs.</td>
<td>Social tariffs in place for a targeted customer group (usually less than 20% of the population) accompanying the transition towards market base prices.</td>
<td>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%.</td>
<td>Allowing price regulation exclusively for clearly defined vulnerable customer groups would ensure that it is a targeted and transitional measure.</td>
<td>Vulnerable households save 20% on their annual electricity bills.</td>
</tr>
</tbody>
</table>

**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. 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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471 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.
Phasing out regulated prices

Graph comparing energy prices before and after policy measures in Denmark and Spain.
Phasing out regulated prices
Phasing out regulated prices

Croatia

Hungary

before policy measure

after policy measure

€

Kw/h

before policy measure

after policy measure

€
Phasing out regulated prices

Graphs showing the comparison of energy prices before and after policy measures in Italy and Lithuania.
Phasing out regulated prices
Phasing out regulated prices

---

**Poland**

- **Before policy measure**
- **After policy measure**

---

**Portugal**

- **Before policy measure**
- **After policy measure**

---

*Note:.* The graphs illustrate the change in regulated prices before and after policy measures in Poland and Portugal.
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

<table>
<thead>
<tr>
<th></th>
<th>Option 1</th>
<th></th>
<th>Option 2a</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Share of vulnerable households</td>
<td>Total HH consumption</td>
<td>Total electricity subsidised for vulnerable consumers</td>
<td>Total electricity subsidised - vulnerable households</td>
</tr>
<tr>
<td></td>
<td>TWh</td>
<td>TWh</td>
<td>TWh</td>
<td>TWh</td>
</tr>
<tr>
<td>BG</td>
<td>41%</td>
<td>10.6</td>
<td>4.3</td>
<td>1.3</td>
</tr>
<tr>
<td>CY</td>
<td>28%</td>
<td>1.4</td>
<td>0.4</td>
<td>0.1</td>
</tr>
<tr>
<td>DK</td>
<td>3%</td>
<td>10.1</td>
<td>0.3</td>
<td>0.1</td>
</tr>
<tr>
<td>ES</td>
<td>11%</td>
<td>70.7</td>
<td>7.8</td>
<td>2.4</td>
</tr>
<tr>
<td>FR</td>
<td>6%</td>
<td>149.4</td>
<td>8.8</td>
<td>2.6</td>
</tr>
<tr>
<td>GR</td>
<td>33%</td>
<td>17.2</td>
<td>5.6</td>
<td>1.7</td>
</tr>
<tr>
<td>HR</td>
<td>10%</td>
<td>5.6</td>
<td>0.5</td>
<td>0.2</td>
</tr>
<tr>
<td>HU</td>
<td>12%</td>
<td>10.4</td>
<td>1.2</td>
<td>0.4</td>
</tr>
<tr>
<td>IT</td>
<td>18%</td>
<td>64.3</td>
<td>11.6</td>
<td>3.5</td>
</tr>
<tr>
<td>LT</td>
<td>27%</td>
<td>2.7</td>
<td>0.7</td>
<td>0.2</td>
</tr>
<tr>
<td>LV</td>
<td>17%</td>
<td>1.7</td>
<td>0.3</td>
<td>0.1</td>
</tr>
<tr>
<td>MT</td>
<td>22%</td>
<td>0.6</td>
<td>0.1</td>
<td>0.0</td>
</tr>
<tr>
<td>PL</td>
<td>9%</td>
<td>28.0</td>
<td>2.5</td>
<td>0.8</td>
</tr>
<tr>
<td>PT</td>
<td>28%</td>
<td>11.9</td>
<td>3.4</td>
<td>1.0</td>
</tr>
<tr>
<td>RO</td>
<td>12%</td>
<td>11.9</td>
<td>1.5</td>
<td>0.4</td>
</tr>
<tr>
<td>SK</td>
<td>6%</td>
<td>4.9</td>
<td>0.3</td>
<td>0.1</td>
</tr>
<tr>
<td>EU-16 Totals</td>
<td>13%</td>
<td>401.5</td>
<td>49.4</td>
<td>14.8</td>
</tr>
</tbody>
</table>

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 study⁴⁷² 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

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Phasing out regulated prices

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\textsuperscript{474}, under which a company is allowed to charge end customers its total incurred costs

\textsuperscript{473} \textit{"The Cost of Non-Europe in the Single Market for Energy"} (2013) European Parliament
\textsuperscript{474} \textit{"Regulation of the Power Sector"} (2013) Ignacio J. Pérez-Arriaga

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Source: European Parliament\textsuperscript{475}

\textsuperscript{475}
Phasing out regulated prices

Where the investments costs include a fair return on investment.

This example was studied by Pérez-Arriaga\(^{475}\) 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 an approach, as shown in the table below.

<table>
<thead>
<tr>
<th>Cost-of-service regulation</th>
<th>Pros</th>
<th>Cons/risks</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Ensures a fair price at any given time (customers do not overpay and investors are not undercompensated)</td>
<td>Possible cost inflation due to:</td>
</tr>
</tbody>
</table>
|                             | Ensures regulatory stability | - 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).
|                             | Guarantees cost recovery (via suitable remuneration), providing a favourable investment climate, reducing capital costs | - 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.
|                             | Guarantees high levels of security of supply for electricity customers. | - 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.

\(^{475}\) "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" 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).


476 Phasing out regulated prices
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 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

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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** 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 ongoing 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)](https://ep.europa.eu/sides/getDoc.do?pubRef=-//EP//SAO/LIBAT_183478/20160412-00897//EN): "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)](https://ep.europa.eu/sides/getDoc.do?pubRef=-//EP//S//H-05-0089/01//FR): "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 ongoing work on the future Electricity Market Design, [BEUC](https://www.beuc.eu) has argued that price

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**Phasing out regulated prices**
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**

<table>
<thead>
<tr>
<th>Objective: Creating a level playing field for access to data.</th>
<th>Option 0</th>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
</table>
| **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\(^{479}\).

\(^{479}\) "Benchmarking smart metering deployment in the EU-27 with a focus on electricity". 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 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.

480 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](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.

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.

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481 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.

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 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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Creating a level playing field for access to 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.
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, 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."

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;"
Creating a level playing field for access to 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:** | **Pros:** | **Pros:** | **Pros:** |
| - Evidence may suggest a degree of non-enforcement of existing legislation by national authorities. | - Non-enforcement may be due to complex existing legislation. | - Considerably reduces the prevalence of fees associated with switching suppliers, and hence financial/psychological barriers to switching. | - Completely eliminates one financial/psychological barrier to switching. |
| - No new legislative intervention necessary. | - No new legislative intervention necessary. | - Simple measure removes doubt amongst consumers. | - The clearest, most enforceable requirement without exceptions. |
| **Cons:** | **Cons:** | **Cons:** | **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. | - Marginally reduces the range of contracts available to consumers, thereby limiting innovation. | - 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. |
| - The vast majority of switching-related fees faced by consumers are permitted under current EU legislation. | - Certain Member States might ignore the interpretative note. | - An element of interpretation remains around exceptions to the ban on fees associated with switching suppliers. | - 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\(^5\) 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\(^6\). Whilst data from the mystery shopping exercise is non-exhaustive, the methodology enables the controlled sampling of a very large topic area\(^7\), 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\(^8\) 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**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Mortgages</td>
<td>Yes</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Private life insurance</td>
<td>9%</td>
<td>+1.3*</td>
<td>-0.4</td>
<td>-0.3</td>
<td>+0.3</td>
</tr>
<tr>
<td>Bank accounts</td>
<td>9%</td>
<td>-0.6</td>
<td>-0.3</td>
<td>-0.6</td>
<td>+0.2</td>
</tr>
<tr>
<td>TV-subscriptions</td>
<td>9%</td>
<td>+2.3*</td>
<td>-0.8*</td>
<td>-2.2*</td>
<td></td>
</tr>
<tr>
<td>Gas services</td>
<td>9%</td>
<td>+1.0*</td>
<td>+2.0*</td>
<td>-0.9*</td>
<td>+0.3</td>
</tr>
<tr>
<td>Home insurance</td>
<td>8%</td>
<td>+0.6</td>
<td>+0.2</td>
<td>+0.4</td>
<td>-0.6</td>
</tr>
<tr>
<td>Loans, credit and credit cards</td>
<td>10%</td>
<td>+1.3*</td>
<td>-0.2</td>
<td>+0.1</td>
<td></td>
</tr>
<tr>
<td>Fixed telephone services</td>
<td>10%</td>
<td>+1.6*</td>
<td>-0.7*</td>
<td>-0.5</td>
<td>+0.2</td>
</tr>
<tr>
<td>Electricity services</td>
<td>10%</td>
<td>+2.4*</td>
<td>-0.4</td>
<td>-0.2</td>
<td>+1.8*</td>
</tr>
<tr>
<td>Investment products, private pensions and securities</td>
<td>14%</td>
<td>+2.2*</td>
<td>-0.7</td>
<td>-0.2</td>
<td>-3.6*</td>
</tr>
<tr>
<td>Internet provision</td>
<td>13%</td>
<td>+1.6*</td>
<td>+0.1</td>
<td>-0.1</td>
<td>+0.2</td>
</tr>
<tr>
<td>Mobile telephone services</td>
<td>15%</td>
<td>+3.1*</td>
<td>+0.1</td>
<td>0.0</td>
<td>+0.6</td>
</tr>
<tr>
<td>Commercial sport services</td>
<td>16%</td>
<td>+3.8*</td>
<td>-0.4</td>
<td>-0.5</td>
<td>+1.3*</td>
</tr>
<tr>
<td>Vehicle insurance</td>
<td>16%</td>
<td>+2.6*</td>
<td>-1.4*</td>
<td>+1.0*</td>
<td>+0.5</td>
</tr>
<tr>
<td>Switching markets</td>
<td>11%</td>
<td>+1.8*</td>
<td>-0.3*</td>
<td>-0.4*</td>
<td>-0.3*</td>
</tr>
</tbody>
</table>

**Source:** Market Monitoring Survey, 2015

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\(^5\) The Czech Republic, France, Germany, Italy, Lithuania, Poland, Slovenia, Spain, Sweden and the UK.


\(^7\) 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.

\(^8\) The percentage of consumers changing suppliers in any given year.
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

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 early⁴⁸⁹. 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

⁴⁸⁹ 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

<table>
<thead>
<tr>
<th></th>
<th>CZ</th>
<th>DE</th>
<th>ES</th>
<th>FR</th>
<th>UK</th>
<th>IT</th>
<th>LT</th>
<th>PL</th>
<th>SE</th>
<th>SI</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>You will not be charged for the change</td>
<td>60%</td>
<td>94%</td>
<td>83%</td>
<td>89%</td>
<td>59%</td>
<td>86%</td>
<td>80%</td>
<td>67%</td>
<td>66%</td>
<td>80%</td>
<td>77%</td>
</tr>
<tr>
<td>A fee for cancelling your current energy deal (e.g. exit fee for fixed rates)</td>
<td>40%</td>
<td>5%</td>
<td>11%</td>
<td>5%</td>
<td>38%</td>
<td>1%</td>
<td>0%</td>
<td>28%</td>
<td>32%</td>
<td>14%</td>
<td>17%</td>
</tr>
<tr>
<td>Another extra charge</td>
<td>0%</td>
<td>0%</td>
<td>7%</td>
<td>4%</td>
<td>3%</td>
<td>11%</td>
<td>8%</td>
<td>4%</td>
<td>2%</td>
<td>2%</td>
<td>4%</td>
</tr>
<tr>
<td>No response</td>
<td>0%</td>
<td>1%</td>
<td>0%</td>
<td>1%</td>
<td>0%</td>
<td>1%</td>
<td>12%</td>
<td>1%</td>
<td>0%</td>
<td>4%</td>
<td>2%</td>
</tr>
</tbody>
</table>

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". As checks by the Commission

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490 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
Facilitating supplier switching

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)

<table>
<thead>
<tr>
<th>Extra Charge Description</th>
<th>Country</th>
</tr>
</thead>
<tbody>
<tr>
<td>Administration cost (EUR 35)</td>
<td>France</td>
</tr>
<tr>
<td>A service fee (EUR 27.90)</td>
<td>France</td>
</tr>
<tr>
<td>A fee for starting up the service (EUR 27.16)</td>
<td>France</td>
</tr>
<tr>
<td>An administration cost added on the first electricity bill (EUR 27.59)</td>
<td>Italy</td>
</tr>
<tr>
<td>An activation fee – Italy, Poland</td>
<td></td>
</tr>
<tr>
<td>An extra charge of EUR 20.54 on the first bill; no explanation was provided for this charge – Italy</td>
<td>Italy</td>
</tr>
<tr>
<td>A security deposit (EUR 70) – Italy</td>
<td></td>
</tr>
<tr>
<td>A deposit (EUR 77) – Italy</td>
<td>Italy</td>
</tr>
<tr>
<td>A fee for contracts of less than one year – Spain</td>
<td>Spain</td>
</tr>
<tr>
<td>A yearly charge of 300 SEK/year (or 25 SEK/month) for each new contract – Sweden</td>
<td>Sweden</td>
</tr>
</tbody>
</table>

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.
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). 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 scenario.

Source: ACER.

491 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.

context. 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 both 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.

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).

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 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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494 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.
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.

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.

Source: "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission

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"."

For more details, see the Thematic Evaluation on Metering and Billing.
Facilitating supplier switching

Table 2: Switching rules found on electricity companies’ websites

<table>
<thead>
<tr>
<th>Rule</th>
<th>SI</th>
<th>DE</th>
<th>UK</th>
<th>FR</th>
<th>PL</th>
<th>CZ</th>
<th>IT</th>
<th>LT</th>
<th>SE</th>
<th>ES</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>You will not be charged for the change</td>
<td>82%</td>
<td>57%</td>
<td>21%</td>
<td>52%</td>
<td>50%</td>
<td>36%</td>
<td>45%</td>
<td>30%</td>
<td>10%</td>
<td>24%</td>
<td>42%</td>
</tr>
<tr>
<td>The new provider must make the change within three weeks (or less), provided you respect the terms and conditions of the original contract</td>
<td>10%</td>
<td>13%</td>
<td>26%</td>
<td>13%</td>
<td>6%</td>
<td>8%</td>
<td>1%</td>
<td>10%</td>
<td>12%</td>
<td>3%</td>
<td>10%</td>
</tr>
<tr>
<td>Within six weeks (or less) after you switch, you should receive the final closure account from your previous provider</td>
<td>10%</td>
<td>11%</td>
<td>24%</td>
<td>4%</td>
<td>7%</td>
<td>2%</td>
<td>0%</td>
<td>2%</td>
<td>2%</td>
<td>4%</td>
<td>7%</td>
</tr>
<tr>
<td>It might be that you’ll incur a fee for cancelling your current energy deal</td>
<td>10%</td>
<td>5%</td>
<td>17%</td>
<td>0%</td>
<td>6%</td>
<td>8%</td>
<td>1%</td>
<td>0%</td>
<td>16%</td>
<td>5%</td>
<td>7%</td>
</tr>
<tr>
<td>None of the above</td>
<td>14%</td>
<td>38%</td>
<td>42%</td>
<td>43%</td>
<td>47%</td>
<td>52%</td>
<td>54%</td>
<td>66%</td>
<td>66%</td>
<td>69%</td>
<td>49%</td>
</tr>
</tbody>
</table>

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.

497 Question: "Which of the following statements about the switching process were found on the website? (multiple answers allowed)"
Figure 7: Main reasons for not trying to switch electricity company

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 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\(^{499}\);
- Gas household consumers see no benefits\(^{500}\);
- 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\(^{501}\);
- The financial advantage of switching as a result of these measures persists for four years\(^{502}\);
- All EU households within each Member State are able to benefit from these changes equally in relative terms\(^{503}\);
- 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

\(^{499}\) 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.

\(^{500}\) 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.


\(^{502}\) 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.

\(^{503}\) 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.
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.

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 supranational 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; 504
- 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; 505
- Gas household consumers see no benefits; 506
- The financial advantage of switching as a result of these measures persists for four years; 507
- All EU households within each Member State are able to benefit from these changes equally in relative terms; 508
- 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.

504 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.


506 This is a conservative estimate. Whilst the evidence suggests they may be less prevalent, Figures 4 and 5 indicate they are certainly present.

507 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.

508 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.
In addition, Option 1 would permit the on-bill repayment of upfront investments in energy efficiency. Such financing through, for instance, energy performance contracting\(^{509}\) 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.

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\(^{510}\);
- 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\(^{511}\);
- Gas household consumers see no benefits\(^{512}\);
- The financial advantage of switching as a result of these measures persists for four years\(^{513}\);
- All EU households within each Member State are able to benefit from these changes equally in relative terms\(^{514}\);
- A discount rate of 4% for the consumer benefits year on year;

---

\(^{509}\) “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.

\(^{510}\) See Figure 7. This estimate is based on survey responses, and has been discounted to conservatively reflect possible unreliability in what consumers report.

\(^{511}\) 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.

\(^{512}\) This is a conservative estimate. Whilst the evidence suggests they may be less prevalent, Figure 4 and Figure 5 indicate they are certainly present.

\(^{513}\) 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.

\(^{514}\) 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 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.

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 Market515 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.

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, CEER516, 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.

516 The Council of European Energy Regulators.
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. 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."

BEUC, EURELECTRIC and Eurogas recently released joint statement on improved comparability of energy offers. 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.)
- 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) called for: "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

<table>
<thead>
<tr>
<th>Objective: Facilitating supplier switching by improving consumer access to reliable comparison tools.</th>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cross-sectorial Commission guidance addressing the applicability of the Unfair Commercial Practices Directive to comparison tools</strong></td>
<td>Legislation to ensure every Member State has at least one 'certified' comparison tool that complies with pre-specified criteria on reliability and impartiality</td>
<td>Legislation to ensure every Member State appoints an independent body to provide a comparison tool that serves the consumer interest</td>
</tr>
</tbody>
</table>

**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.

**Cons:**
- Does not apply to non-profit comparison tools.
- Does not proactively increase levels of consumer trust.
- The existing legislation does not obligate comparison tools to be fully impartial, comprehensive, effective or useful to the consumer.

**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.

**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.

**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:**
- 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).
Table 1: Estimated number of energy comparison tools in Member States

<table>
<thead>
<tr>
<th>Member State</th>
<th>Number of energy CTs</th>
<th>Of which Govt. Operated</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>AT</td>
<td>2*</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>BE</td>
<td>11</td>
<td>3</td>
<td>Accreditation under review.</td>
</tr>
<tr>
<td>BG</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>CZ</td>
<td>2*</td>
<td>0*</td>
<td></td>
</tr>
<tr>
<td>DE</td>
<td>10</td>
<td>0</td>
<td>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.</td>
</tr>
<tr>
<td>DK</td>
<td>2</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>EE</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>EL</td>
<td>3*</td>
<td>0*</td>
<td></td>
</tr>
<tr>
<td>ES</td>
<td>7</td>
<td>1</td>
<td>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.</td>
</tr>
<tr>
<td>FI</td>
<td>4</td>
<td>1</td>
<td>No specific accreditation standards are applied. The CT (<a href="http://www.sahkonhinta.fi">www.sahkonhinta.fi</a>) 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.</td>
</tr>
<tr>
<td>FR</td>
<td>8</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>HU</td>
<td>3</td>
<td>0</td>
<td>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.</td>
</tr>
<tr>
<td>HR</td>
<td>1*</td>
<td>0*</td>
<td></td>
</tr>
<tr>
<td>IE</td>
<td>2*</td>
<td>0</td>
<td>Accreditation scheme in place</td>
</tr>
<tr>
<td>IT</td>
<td>9</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>LV</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>LT</td>
<td>0</td>
<td>0</td>
<td>ACER reports no price comparison tools in this Member State.</td>
</tr>
<tr>
<td>LU</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
</tbody>
</table>

* denotes estimate based on weighted average of figures from NRAs who reported data, or desktop research

<table>
<thead>
<tr>
<th>Member State</th>
<th>Number of energy CTs</th>
<th>Of which Govt. Operated</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>NL</td>
<td>14</td>
<td>0</td>
<td>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.</td>
</tr>
<tr>
<td>PL</td>
<td>1</td>
<td>1</td>
<td>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.</td>
</tr>
<tr>
<td>PT</td>
<td>2</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>RO</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>SE</td>
<td>4</td>
<td>1</td>
<td>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.</td>
</tr>
<tr>
<td>SI</td>
<td>1*</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>SK</td>
<td>1*</td>
<td>0*</td>
<td></td>
</tr>
<tr>
<td>UK</td>
<td>34</td>
<td>1</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>122</strong>*</td>
<td><strong>18</strong>*</td>
<td></td>
</tr>
</tbody>
</table>

* denotes estimate based on weighted average of figures from NRAs who reported data, or desktop research

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.\(^{521}\) It also showed that comparison tools significantly increased the number of cheaper offers consumers were able to identify compared with contacting individual providers directly.\(^{522}\) Overall, 23% of consumers surveyed in the EU have used a comparison tool to compare energy offers in the last 12 months.\(^{523}\)

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\(^{521}\) Non-exclusive figures i.e. respondents could choose more than one means of comparison.

\(^{522}\) 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.

\(^{523}\) 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.\(^{524}\)

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).

Figure 1: Business models of EU comparison tools (including non-energy)

![Business Models of EU Comparison Tools]

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".

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.

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525 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

| 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 (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.

526 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.

527 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

<table>
<thead>
<tr>
<th>Document</th>
</tr>
</thead>
<tbody>
<tr>
<td>Directive 2011/83/EU (Consumer Rights Directive)</td>
</tr>
<tr>
<td>Directive 2006/114/EC (Misleading and Comparative Advertising Directive)</td>
</tr>
<tr>
<td>Directive 98/6/EU (Price Indication Directive)</td>
</tr>
<tr>
<td>Directive 2014/92/EU (Payment Accounts Directive)</td>
</tr>
<tr>
<td>Regulation (EC) No 1008/2008 (Air Services Regulation)</td>
</tr>
<tr>
<td>Directive 2009/73/EC (Gas Directive)</td>
</tr>
<tr>
<td>Directive 2007/64/EC (Payment Services Directive)</td>
</tr>
<tr>
<td>Directive 2002/65/EC (Distance Marketing of Consumer Financial Services Directive)</td>
</tr>
</tbody>
</table>

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.528

In addition, various other cross-sectorial consumer protection Directives require the disclosure of price and product data sourcing.529 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 "enforcement of existing legal instruments appears to be first a priority".530

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.531 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.

529 "Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools" (2013) European Commission, pp. 289.
530 "Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools" (2013) European Commission, pp. 287.
Box 3: Fourteen CEER recommendations for comparison tools

<table>
<thead>
<tr>
<th>Recommendation</th>
</tr>
</thead>
<tbody>
<tr>
<td>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).</td>
</tr>
<tr>
<td>Transparency: Comparison Tools should disclose the way they operate, their funding and their owners/shareholders (3).</td>
</tr>
<tr>
<td>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).</td>
</tr>
<tr>
<td>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).</td>
</tr>
<tr>
<td>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).</td>
</tr>
<tr>
<td>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).</td>
</tr>
<tr>
<td>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).</td>
</tr>
<tr>
<td>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).</td>
</tr>
</tbody>
</table>

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. 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).

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 supranational 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. 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.

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533 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,
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. 

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534 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, one dimension of consumer surplus – the direct financial benefits to

535 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;\(^{536}\);
- 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) increased by 0.1% as a result of the intervention;\(^{538}\);
- 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);\(^{539}\);
- 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;\(^{541}\);
- All EU households within each Member State are able to benefit from these changes equally in relative terms;\(^{542}\);
- 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

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\(^{536}\) 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.

\(^{537}\) CY and MT were not included in this analysis.

\(^{538}\) 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.

\(^{539}\) 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.

\(^{540}\) 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.

\(^{541}\) A conservative assumption in light of Figure 2.

\(^{542}\) 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**

<table>
<thead>
<tr>
<th>Costs Description</th>
<th>Amount (EUR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial investment (2008)</td>
<td>107,000</td>
</tr>
<tr>
<td>IT system upgrade (2014)</td>
<td>29,400</td>
</tr>
<tr>
<td>Website upgrade (2015)</td>
<td>63,600</td>
</tr>
<tr>
<td>Annual running costs:</td>
<td></td>
</tr>
<tr>
<td>License</td>
<td>2,996</td>
</tr>
<tr>
<td>Servers and storage</td>
<td>7,704</td>
</tr>
<tr>
<td>Application support and CGI</td>
<td>16,050</td>
</tr>
<tr>
<td>1 to 1.7 fulltime positions, depending on the year</td>
<td>66,768 - 113,506</td>
</tr>
<tr>
<td>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.</td>
<td></td>
</tr>
</tbody>
</table>

**Box 5: The costs of operating Ofgem's confidence code for comparison tools**

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)

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543 Labour costs assume 2,080 work hours per man-year at EUR 32.10 for professionals, as per the standard cost model.
544 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;\(^5\)\(^4\)\(^6\),
- The cost of voluntary accreditation schemes to comparison tools is zero;\(^5\)\(^4\)\(^7\),
- 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\(^5\)\(^4\)\(^8\). Given these results, one might expect Option 2 to lead to greater levels of consumer trust than Option 1.

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\(^5\)\(^4\)\(^5\) 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.

\(^5\)\(^4\)\(^6\) 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).

\(^5\)\(^4\)\(^7\) As the scheme is voluntary, comparison tools can be expected to only make the changes necessary to qualify for accreditation if they judged this would be in their long-term financial interest anyway.

\(^5\)\(^4\)\(^8\) "Study on the coverage, functioning and consumer use of comparison tools and third-party verification schemes for such tools" (2013) European Commission, p. 203.
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) increased by 0.13% as a result of the intervention – 30% more than option one;
- 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);
- The financial advantage of switching as a result of these measures persists for four years;
- Apart from increasing the switching rate, there were no other benefits of this intervention in terms of improving the ability of switching customers to identify a better offer;
- All EU households within each Member State are able to benefit from these changes equally in relative terms;
- A discount rate of 4% for the consumer benefits year on year;

Question: "Comparison tools can be run by different types of organisations. Among the following organisations, which one do you think is the most appropriate?"

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

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. 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);
- 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

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556 The costs to suppliers in terms of notifying such sites of their is not considered significant.
557 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.
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\(^\text{558}\)).

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.

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 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


517
Comparison tools
CEER\textsuperscript{560} 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\textsuperscript{561}.

\textit{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\textsuperscript{562}.

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).

\textit{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.

\footnotesize{\textsuperscript{560} The Council of European Energy Regulators.}

\footnotesize{\textsuperscript{561} http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Ta b3/C12-CEM-54-03_GGP-PCT_09Jul2012.pdf}

\footnotesize{\textsuperscript{562} http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Ta b3/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 market563.

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

2012 CEER Guidelines of Good Practice on Price Comparison Tools\textsuperscript{564}. 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\textsuperscript{565}.

\textit{The European Parliament}

In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the Parliament's \textbf{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: "\textit{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 \textbf{Committee on the Internal Market and Consumer Protection (IMCO)} called on the Commission: "\textit{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 "\textit{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: "\textit{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: "\textit{access for all consumers to at least one price comparison tool for energy services.}"

\textit{The Committee of the Regions}

In its April 2016 opinion on the Commission's Communication on Delivering a New Deal for Energy Consumers, the \textbf{Committee of the Regions} supports the idea of ensuring that each consumer has access to at least one independent and verified

\textsuperscript{564} http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab3/C12-CEM-54-03_GGP-PCT_09Jul2012.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.

<table>
<thead>
<tr>
<th>Option: BAU/Stronger enforcement</th>
<th>Option 0+</th>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pros:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- 77% of energy consumers agree or strongly agree that bills are &quot;easy and clear to understand&quot;.</td>
<td>- Low administrative impact</td>
<td>- Ensures that the minimum baseline of existing practices is clarified and raised.</td>
<td>- Highest legal clarity and comparability of offers and bills.</td>
</tr>
<tr>
<td>- Allows 'natural experiments' and other innovation on the design of billing information to be developed by Member State.</td>
<td>- Gives Member State significant flexibility to adapt their requirements to national conditions.</td>
<td>- Allows best practices to further develop, albeit less than Option 0.</td>
<td>- A level playing field for all consumers and suppliers across the EU.</td>
</tr>
<tr>
<td>- Recent (2014) transposition of the EED means premature to address information on energy consumption and costs.</td>
<td>- Allows best practices to further develop.</td>
<td>- Improves comparability and portability of information.</td>
<td>- Very little leeway for suppliers to differently interpret the legislation with regards to the presentation of information.</td>
</tr>
<tr>
<td><strong>Cons:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Poor consumer awareness of market-relevant information can be expected to continue.</td>
<td>- A recommendation is unenforceable and may be ignored by Member State/utilities.</td>
<td>- Limits innovation around certain bill elements.</td>
<td>- Challenging to devise standard presentation which can accommodate differences between national markets.</td>
</tr>
<tr>
<td>- Does not respond to stakeholder feedback on need to ensure minimum standards.</td>
<td>- Poor consumer awareness of market-relevant information can be expected to continue.</td>
<td>- Remaining leeway in interpreting legal articles may lead to implementation and enforcement difficulties.</td>
<td>- Highest administrative impact.</td>
</tr>
<tr>
<td><strong>Most suitable option(s):</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>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.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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\textsuperscript{566} 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\textsuperscript{567}. Whilst data from the mystery shopping exercise is non-exhaustive, the methodology enables the controlled sampling of a very large topic area\textsuperscript{568}, 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

\textsuperscript{566} The Czech Republic, France, Germany, Italy, Lithuania, Poland, Slovenia, Spain, Sweden and the UK.

\textsuperscript{567} "Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU" (2016) European Commission.

\textsuperscript{568} 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**

<table>
<thead>
<tr>
<th>The following information must be grouped together, in a box, distinct from other information and included on page one of the Bill:</th>
</tr>
</thead>
<tbody>
<tr>
<td>- The standardised title “Could you pay less?”</td>
</tr>
<tr>
<td>- Information on cheaper tariffs offered by the supplier and the savings available if the consumer were to switch.</td>
</tr>
<tr>
<td>- A Personal Projection* for the consumer's current tariff.</td>
</tr>
<tr>
<td>- A signpost to further tariff information.</td>
</tr>
<tr>
<td>- A standardised switching reminder “Remember – it might be worth thinking about switching your tariff or supplier”.</td>
</tr>
</tbody>
</table>

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.

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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**

<table>
<thead>
<tr>
<th>Country</th>
<th>Practice and Regulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria (MI)</td>
<td>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.</td>
</tr>
<tr>
<td>Belgium (HP)</td>
<td>Law April, 29th 1999 ‘Loi relative à l'organisation du marché de l'électricité’ 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.</td>
</tr>
<tr>
<td>Bulgaria (BF)</td>
<td>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.</td>
</tr>
<tr>
<td>Croatia (MI)</td>
<td>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.</td>
</tr>
<tr>
<td>Cyprus (MI)</td>
<td>Article 91 (1)(d)(iv) and Article 93 (1)(j) of the Electricity Law 206(1)/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).</td>
</tr>
<tr>
<td>Czech Republic (DF)</td>
<td>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...</td>
</tr>
</tbody>
</table>

**570 “Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU” (2016) European Commission.**
<table>
<thead>
<tr>
<th>Country</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denmark (MI)</td>
<td>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.</td>
</tr>
<tr>
<td>Estonia (MI)</td>
<td>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.</td>
</tr>
<tr>
<td>Finland (MI)</td>
<td>Part III, Ch. 9, §9 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.</td>
</tr>
<tr>
<td>France (HP)</td>
<td>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.</td>
</tr>
<tr>
<td>Germany (MI)</td>
<td>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.</td>
</tr>
<tr>
<td>Greece (BF)</td>
<td>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.</td>
</tr>
<tr>
<td>Hungary (HP)</td>
<td>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.</td>
</tr>
<tr>
<td>Ireland (MI)</td>
<td>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.</td>
</tr>
<tr>
<td>Italy (MI)</td>
<td>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 (onere 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 &quot;Your Bill Explained&quot; (la bolletta spiegata) and a consumer help-desk (lo Sportello per il Consumatore).</td>
</tr>
<tr>
<td>Latvia (MI)</td>
<td>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.</td>
</tr>
<tr>
<td>Lithuania (BF)</td>
<td>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</td>
</tr>
</tbody>
</table>

**Improving billing information**
<table>
<thead>
<tr>
<th>Country</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Luxembourg (BF)</td>
<td>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.</td>
</tr>
<tr>
<td>Malta (MI)</td>
<td>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 CO₂ emissions.</td>
</tr>
<tr>
<td>Netherlands (MI)</td>
<td>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”).</td>
</tr>
<tr>
<td>Poland (MI)</td>
<td>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.</td>
</tr>
<tr>
<td>Portugal (BF)</td>
<td>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.</td>
</tr>
<tr>
<td>Romania (HP)</td>
<td>Law 123/2012 (modified in 2014) ART.62 (1) h”) 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.</td>
</tr>
<tr>
<td>Slovakia (MI)</td>
<td>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.</td>
</tr>
<tr>
<td>Slovenia (MI)</td>
<td>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 CO₂ emissions and amounts of radioactive waste resulting from the electricity production in the preceding year, and consumers’ rights related to dispute resolution.</td>
</tr>
<tr>
<td>Spain (HP)</td>
<td>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.</td>
</tr>
</tbody>
</table>
Improving billing information

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.
The results of a mystery shopping exercise on the information in energy bills covering ten representative Member States 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 (Table 2) as well as a number of information elements addressed (although not always required) by the current Electricity Directive (Table 3). The exercise was carried out between 11 December 2014 and 18 March 2015.

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571 The Czech Republic, France, Germany, Italy, Lithuania, Poland, Slovenia, Spain, Sweden and the UK.
Table 2: Information included on an electricity bill in a sample of ten Member States - 1

<table>
<thead>
<tr>
<th>Item</th>
<th>Item in &quot;billing&quot; evaluation sheet</th>
<th>Country</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supplier's name</td>
<td>Provider’s name</td>
<td>% who found item on their bill (total)</td>
</tr>
<tr>
<td>99%</td>
<td>96%</td>
<td>100%</td>
</tr>
<tr>
<td>Contact details (including their helpline and emergency number)</td>
<td>Telephone number of customer service/helpline</td>
<td>96%</td>
</tr>
<tr>
<td>Postal address of provider</td>
<td>94%</td>
<td>92%</td>
</tr>
<tr>
<td>Email address of provider</td>
<td>69%</td>
<td>92%</td>
</tr>
<tr>
<td>Emergency number (e.g. to call in the event of an electrical emergency or power outage)</td>
<td>59%</td>
<td>68%</td>
</tr>
<tr>
<td>The duration of the contract</td>
<td>Duration of the contract (e.g. 24 months)</td>
<td>22%</td>
</tr>
<tr>
<td>The deadline for informing the supplier about switching to another supplier</td>
<td>The period of notice to terminate your electricity contract (e.g. 30 days before the intended termination date)</td>
<td>19%</td>
</tr>
<tr>
<td>The tariff name</td>
<td>Tariff name/plan (e.g. 'Day &amp; Night Fix')</td>
<td>80%</td>
</tr>
<tr>
<td>(A reference to) a clear price breakdown for the tariff (the base price plus all other charges and...</td>
<td>A detailed price breakdown for your tariff (e.g. division of total</td>
<td>79%</td>
</tr>
</tbody>
</table>

575 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.
<table>
<thead>
<tr>
<th>Item</th>
<th>Item in “billing” evaluation sheet</th>
<th>Country</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>% who found item on their bill (total)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CZ</td>
</tr>
<tr>
<td>taxes)</td>
<td>price in base price, network charge, etc.)</td>
<td>82%</td>
</tr>
<tr>
<td>The base price of one energy unit (in kilowatt hours or kWh) for the selected tariff</td>
<td>Base price per kWh of your tariff</td>
<td>82%</td>
</tr>
<tr>
<td>The switching code</td>
<td>Switching code/meter identification (EAN or MPAN code; a unique code for your electricity meter)</td>
<td>73%</td>
</tr>
<tr>
<td>The amount to be paid, for which billing period, by when and how</td>
<td>Amount to be paid</td>
<td>97%</td>
</tr>
<tr>
<td></td>
<td>Billing period (e.g. 15 November – 14 December 2014)</td>
<td>95%</td>
</tr>
<tr>
<td></td>
<td>Payment method (e.g. direct deposit, cheque, bank transfer)</td>
<td>84%</td>
</tr>
<tr>
<td>Clear information on how this amount has been calculated: is it based on an actual meter reading or estimated only?</td>
<td>% of shoppers stating that it not clear how the billing amount was calculated</td>
<td>5%</td>
</tr>
<tr>
<td>For calculations based on actual consumption: meter readings and consumption during the billing period (measured in kilowatt hours or kWh)</td>
<td>Details about consumption during billing period (in kWh)</td>
<td>89%</td>
</tr>
<tr>
<td></td>
<td>Value of the meter reading at the end of the billing period</td>
<td>89%</td>
</tr>
<tr>
<td></td>
<td>Value of the meter reading at the beginning of the billing period</td>
<td>88%</td>
</tr>
<tr>
<td>Where does the energy come from, how is it generated, how environment friendly is it (&quot;the fuel mix&quot;)</td>
<td>Fuel mix/energy sources (e.g. wind power, biomass)</td>
<td>32%</td>
</tr>
<tr>
<td>Information on how to get tips on saving energy (e.g. a link to a website)</td>
<td>Tips on saving energy (e.g. link to a website)</td>
<td>26%</td>
</tr>
<tr>
<td>Information on how to obtain the bill in alternative formats (e.g. in large print) for</td>
<td>Information on how to obtain your bill in alternative format</td>
<td>24%</td>
</tr>
</tbody>
</table>
### Improving billing information

<table>
<thead>
<tr>
<th>Item</th>
<th>Item in &quot;billing&quot; evaluation sheet</th>
<th>% who found item on their bill (total)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>CZ</td>
</tr>
<tr>
<td>consumers with disabilities (e.g. paper/online, large print)</td>
<td>300</td>
<td>25</td>
</tr>
<tr>
<td>Base (note: figures in grey are based on a smaller sample):</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Table 3: Information included on an electricity bill in a sample of ten Member States - II

<table>
<thead>
<tr>
<th>Item</th>
<th>Item in “billing” evaluation sheet</th>
<th>% who found item on their bill (total)</th>
<th>Country</th>
<th>Czech Republic</th>
<th>Germany</th>
<th>Spain</th>
<th>France</th>
<th>Italy</th>
<th>Lithuania</th>
<th>Poland</th>
<th>Sweden</th>
<th>Slovenia</th>
<th>United Kingdom</th>
</tr>
</thead>
<tbody>
<tr>
<td>The contribution of each energy source to the overall fuel mix of the supplier over the preceding year</td>
<td>13a. Fuel mix/energy sources (e.g. wind power, biomass)</td>
<td>32%</td>
<td></td>
<td>48%</td>
<td>45%</td>
<td>20%</td>
<td>47%</td>
<td>43%</td>
<td>0%</td>
<td>18%</td>
<td>52%</td>
<td>40%</td>
<td>13%</td>
</tr>
<tr>
<td>Information concerning the consumer's rights as regards the means of dispute settlement available to them in the event of a dispute</td>
<td>8b. National contact information point (or single point of contact where you can obtain information about your energy rights)</td>
<td>28%</td>
<td></td>
<td>44%</td>
<td>43%</td>
<td>33%</td>
<td>43%</td>
<td>30%</td>
<td>4%</td>
<td>3%</td>
<td>16%</td>
<td>12%</td>
<td>53%</td>
</tr>
<tr>
<td>8c. An energy mediator or third-party assistance</td>
<td></td>
<td>23%</td>
<td></td>
<td>36%</td>
<td>45%</td>
<td>23%</td>
<td>57%</td>
<td>0%</td>
<td>0%</td>
<td>3%</td>
<td>12%</td>
<td>0%</td>
<td>50%</td>
</tr>
<tr>
<td>Base:</td>
<td></td>
<td>300</td>
<td></td>
<td>25</td>
<td>40</td>
<td>30</td>
<td>30</td>
<td>25</td>
<td>40</td>
<td>25</td>
<td>25</td>
<td>30</td>
<td></td>
</tr>
</tbody>
</table>

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. 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. 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).

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.

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577 '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...'

578 '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.'

579 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”.
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).

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 choice581. There exist various data that help us understand how EU consumers perceive their energy bills and the extent

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581 Boost competition on retail markets and create consumer incentives to save energy were other major objectives. See the Thematic Evaluation on Metering and billing.
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. 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).


Figure 4: Agreement with statement: “bills of my electrify company are easy and clear to understand”, by country


Figure 5: Agreement with the statement: “My bill is easy to understand”


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, 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

584 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.”

585 Agreement with the statement: “My bill is easy to understand.”

586 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**

![Pie chart showing consumer complaints]

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.
Improving billing information

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.


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”.

- I know how much I pay for electricity (per month, year or any other frequency)
- I know how much electricity I use (per month, year or any other frequency) in kWh
- I know the main characteristics of the tariff I am on [e.g. whether I am on a fixed or variable price, the use of renewable energy, etc.]
- I know how the price I pay for electricity is calculated
- I know how the electricity that I use is produced [e.g. nuclear generation, wind, gas, solar, petroleum, coal, etc.]

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. Presentation of the options

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 initially identified by the Citizens' Energy Forum Working Group on Billing in 2009. 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.

588 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).

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\(^\text{590}\). 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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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. The importance of the information items was then reaffirmed by a Working Group on e-Billing and Personal Data Management in 2013. 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. According to CEER, 6.3% of electricity consumers and 5.5% of gas consumers switched energy suppliers in 2014.

If we assume that:

593 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\textsuperscript{594};
- The measures improved the ability of one out of every one-hundred customers who switched to identify a better offer\textsuperscript{595};
- The measures benefitted consumers using comparison tools just as much as those comparing the market directly through suppliers\textsuperscript{596};
- 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\textsuperscript{597};
- The financial advantage of being able to identify the best deal as a result of these measures persists for four years\textsuperscript{598};
- All EU households are able to benefit from these changes equally in relative terms\textsuperscript{599};
- A discount rate of 4% for the consumer benefits year on year;

The measures improved the ability of one out of every one-hundred customers who switched to identify a better offer. 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.

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\textsuperscript{594} 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.

\textsuperscript{595} 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.

\textsuperscript{596} 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).

\textsuperscript{597} 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.

\textsuperscript{598} 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.

\textsuperscript{599} 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

<table>
<thead>
<tr>
<th>Item</th>
<th>Item in “billing” evaluation sheet</th>
<th>% who found item on their bill (total)</th>
</tr>
</thead>
<tbody>
<tr>
<td>i) The amount to be paid, for which billing period, by when and how (existing EU legal requirement)</td>
<td>Amount to be paid</td>
<td>97%</td>
</tr>
<tr>
<td></td>
<td>Billing period (e.g. 15 November – 14 December 2014)</td>
<td></td>
</tr>
<tr>
<td>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)</td>
<td>Details about consumption during billing period (in kWh)</td>
<td>89%</td>
</tr>
<tr>
<td></td>
<td>Value of the meter reading at the end of the billing period</td>
<td>89%</td>
</tr>
<tr>
<td></td>
<td>Value of the meter reading at the beginning of the billing period</td>
<td>88%</td>
</tr>
<tr>
<td>iii) Supplier’s name</td>
<td>Provider’s name</td>
<td>99%</td>
</tr>
<tr>
<td>iv) Contact details (including their helpline and emergency number)</td>
<td>Telephone number of customer service/helpline</td>
<td>96%</td>
</tr>
<tr>
<td></td>
<td>Postal address of provider</td>
<td>94%</td>
</tr>
<tr>
<td></td>
<td>Email address of provider</td>
<td>69%</td>
</tr>
<tr>
<td></td>
<td>Emergency number (e.g. to call in the event of an electrical emergency or power outage)</td>
<td>59%</td>
</tr>
<tr>
<td>v) The tariff name</td>
<td>Tariff name/plan (e.g. 'Day &amp; Night Fix')</td>
<td>80%</td>
</tr>
<tr>
<td>vi) The duration of the contract</td>
<td>Duration of the contract (e.g. 24 months)</td>
<td>22%</td>
</tr>
<tr>
<td>vii) The switching code</td>
<td>Switching code/meter identification (EAN or MPAN code; a unique code for your electricity meter)</td>
<td>73%</td>
</tr>
<tr>
<td>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)</td>
<td>National contact information point (or single point of contact where you can obtain information about your energy rights)</td>
<td>28%</td>
</tr>
<tr>
<td></td>
<td>An energy mediator or third-party assistance</td>
<td>23%</td>
</tr>
</tbody>
</table>

Base (note: figures in grey are based on a smaller sample): 300


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\(^{600}\). 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)\(^{601}\) |
|-----------------|-----------------|------------------|--------------|------------------|------------------|------------------|
| 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\(^{602}\) Professionals | 32.10 | 16 | 1,116,566.40 |
| Bill design | 1449\(^{603}\) 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\(^{604}\) 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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\(^{600}\) Source: CEER National Indicators Database (2015).

\(^{601}\) Derived from the standard cost model for estimating administrative costs.

\(^{602}\) 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.

\(^{603}\) 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.

\(^{604}\) 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**

![Best Practice Bill](image)


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).
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

<table>
<thead>
<tr>
<th>Question</th>
<th>Best practice bill</th>
<th>Standard bill</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>What is the name of your tariff?</td>
<td>90%</td>
<td>86%</td>
<td>5 pp***</td>
</tr>
<tr>
<td>How much are you being charged in total?</td>
<td>90%</td>
<td>87%</td>
<td>3 pp***</td>
</tr>
<tr>
<td>How much electricity did you consume?</td>
<td>91%</td>
<td>87%</td>
<td>4 pp**</td>
</tr>
<tr>
<td>What is the total unit cost of energy excl. VAT?</td>
<td>77%</td>
<td>72%</td>
<td>6 pp***</td>
</tr>
<tr>
<td>What is the standing charge incl. taxes and charges?</td>
<td>82%</td>
<td>78%</td>
<td>4 pp**</td>
</tr>
<tr>
<td>What is the duration of your contract?</td>
<td>90%</td>
<td>80%</td>
<td>10 pp***</td>
</tr>
<tr>
<td>When does your contract expire?</td>
<td>90%</td>
<td>88%</td>
<td>2 pp*</td>
</tr>
<tr>
<td>How much energy did you consume last year?</td>
<td>60%</td>
<td>52%</td>
<td>8 pp***</td>
</tr>
<tr>
<td>Average across all questions</td>
<td>84%</td>
<td>79%</td>
<td>5 pp***</td>
</tr>
</tbody>
</table>


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

<table>
<thead>
<tr>
<th>Bill type</th>
<th>All countries</th>
<th>CZ</th>
<th>DE</th>
<th>ES</th>
<th>FR</th>
<th>UK</th>
<th>IT</th>
<th>LT</th>
<th>PL</th>
<th>SE</th>
<th>SI</th>
</tr>
</thead>
<tbody>
<tr>
<td>Best practice</td>
<td>61%</td>
<td>59%</td>
<td>64%</td>
<td>53%</td>
<td>59%</td>
<td>72%</td>
<td>52%</td>
<td>60%</td>
<td>59%</td>
<td>63%</td>
<td>59%</td>
</tr>
<tr>
<td>Standard</td>
<td>59%</td>
<td>59%</td>
<td>61%</td>
<td>51%</td>
<td>55%</td>
<td>70%</td>
<td>55%</td>
<td>58%</td>
<td>53%</td>
<td>57%</td>
<td>58%</td>
</tr>
</tbody>
</table>


If we assume that:
- The average EU switching rates for electricity and gas remained unchanged at 6.3% and 5.5% respectively;606
- 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;607
- The measures benefitted consumers using comparison tools just as much as those comparing the market directly through suppliers;608
- 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;609
- The financial advantage of being able to identify the best deal as a result of these measures persists for four years;610
- All EU households are able to benefit from these changes equally in relative terms;611

Note: Weighted base varies by treatment: Best practice = 5,042; Standard = 5,014.

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.

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.

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).

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.

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".612

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.613

No running costs are associated with this option due to the computerisation of billing systems.

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611 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 8: Option 2 implementation costs (all one-time costs)\textsuperscript{614}

<table>
<thead>
<tr>
<th>Obligation</th>
<th>Action</th>
<th>Entities concerned</th>
<th>Staff type</th>
<th>Hourly rate (EUR)</th>
<th>Man hours</th>
<th>Activity cost (EUR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incorporating comparison box into bills</td>
<td>Revising national legislation</td>
<td>28\textsuperscript{615}</td>
<td>Legislators, senior officials, managers</td>
<td>41.50</td>
<td>320</td>
<td>371,840.00</td>
</tr>
<tr>
<td>Understanding information obligation</td>
<td>4347\textsuperscript{616}</td>
<td>Professionals</td>
<td></td>
<td>32.10</td>
<td>8</td>
<td>1,116,309.60</td>
</tr>
<tr>
<td>Bill design</td>
<td>4347</td>
<td>Professionals</td>
<td></td>
<td>32.10</td>
<td>144</td>
<td>20,093,572.80</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>21,581,722.40</td>
</tr>
</tbody>
</table>

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\textsuperscript{617}. 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.

\textsuperscript{614} Derived from the standard cost model for estimating administrative costs.

\textsuperscript{615} All Member States. 40 man-days each.

\textsuperscript{616} All electricity and gas supply companies. 18 man-days each.

\textsuperscript{617} 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](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\(^{618}\) 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\(^{619}\) 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


Improving billing information 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.

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, 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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621 The Council of European Energy Regulators.
Improving billing 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 Konsumternas 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 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 CO₂ 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.
Detailed measures assessed under Problem Area 4: the slow deployment of new services, low levels of service and poor retail market performance
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 participate 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](http://cordis.europa.eu/project/rcn/106040_en.html)

**Web Site:** [http://www.discern.eu/](http://www.discern.eu/)

Important project outcome include:

1. 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](http://cordis.europa.eu/project/rcn/101320_en.html)

**Web Site:** [http://www.itesla-project.eu/](http://www.itesla-project.eu/)

Important project outcomes include:

1. 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.

2. A clarification of the data and data exchanges that are necessary to enable the implementation of these coordination aspects.

3. 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.

4. The tools and models allow to reduce 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.

5. 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](http://cordis.europa.eu/project/rcn/101318_en.html)

**Web Site:** [http://www.e-umbrella.eu/](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 minimize 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](http://cordis.europa.eu/project/rcn/106279_en.html)

**Web Site:** [http://www.e-highway2050.eu/e-highway2050/](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](http://cordis.europa.eu/project/rcn/85687_en.html)

**Project website:** [http://www.vsync.eu/](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.


**Project website:** [http://www.reservices-project.eu/](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.
**Project FP7 IDE4L**

**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](http://cordis.europa.eu/project/rcn/109372_en.html)

**Project website:** [http://ide4l.eu/](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

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**Project FP7 NRG4Cast**

**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](http://cordis.europa.eu/search/result_en?q=nrg4cast)

**Project website:** [http://www.nrg4cast.org/](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.
Project FP7 EEPOS
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.
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.

H2020: 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.

Project H2020: 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 website:** http://cordis.europa.eu/project/rcn/103636_en.html

**Project website:** 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](http://cordis.europa.eu/project/rcn/103637_en.html)

**Project web Site:** [http://www.grid4eu.eu](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.

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**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](http://cordis.europa.eu/project/rcn/200558_en.html)

**Project web Site:** [http://www.futureflow.eu/](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.

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**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 website**: http://cordis.europa.eu/project/rcn/100196_en.html  
**Project website**: 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.

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**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 website**: http://cordis.europa.eu/project/rcn/98988_en.html  
**Project website**: 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.

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**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 website**: http://cordis.europa.eu/project/rcn/194422_en.html  
**Project website**: 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.

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**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](http://cordis.europa.eu/project/rcn/105831_en.html)

**Project web Site:**  [http://www.s3c-project.eu/](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 CO2 emission) instead of a purely technical information.

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**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](http://cordis.europa.eu/project/rcn/94493_en.html)

**Project web Site:**  [http://metapv.eu](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.

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**Project FP7-INTrEPID**

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Description of relevant European R&D projects
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

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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 customers’ (EV users) can participate and benefit from (change from customer to prosumer e.g. by offering battery capacity for grid stability services).

**Cordis web site:** [http://cordis.europa.eu/project/rcn/109374_en.html](http://cordis.europa.eu/project/rcn/109374_en.html)

**Project web site:** [http://www.plangridev.eu/](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.