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IMPACT ASSESSMENT

Accompanying the document

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

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

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

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

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1.1. Priority access and dispatch

1.1.1. *Summary table*

Objective: To ensure that all technologies can compete on an equal footing, eliminating provisions which create market distortions unless clear necessity is demonstrated, thus ensuring that the most efficient option for meeting the policy objectives is found. Dispatch should be based on the most economically efficient solution which respects policy objectives.				
	Option 0	Option 1	Option 2	Option 3
Description	Do nothing. This would maintain rules allowing priority dispatch and priority access for RES, indigenous fuels and CHP.	Abolish priority dispatch and priority access This option would generally require full merit order dispatch for all technologies, including RES E, indigenous fuels such as coal, and CHP. It would ensure optimum use of the available network in case of network congestion.	Priority dispatch and/or priority access only for emerging technologies and/or for very small plants: This option would entail maintaining priority dispatch and/or priority access only for small plants or emerging technologies. This could be limited to emerging RES E technologies, or also include emerging conventional technologies, such as CCS or very small CHP.	Abolish priority dispatch and introduce clear curtailment and re-dispatch rules to replace priority access. This option can be combined with Option 2, maintaining priority dispatch/access only for emerging technologies and/or for very small plants
Pros	Lowest political resistance	Efficient use of resources, clearly distinguishes market-based use of capacities and potentially subsidy-based installation of capacities, making subsidies transparent.	Certain emerging technologies require a minimum number of running hours to gather experiences. Certain small generators are currently not active on the wholesale market. In some cases, abolishing priority dispatch could thus bring significant challenges for implementation. Maintaining also priority access for these generators further facilitates their operation.	As Option 1, but also resolves other causes for lack of market transparency and discrimination potential. It also addresses concerns that abolishing priority dispatch and priority access could result in negative discrimination for renewable technologies.
Cons		Politically, it may be criticized that subsidized resources are not always used if there are lower operating cost alternatives. Adds uncertainty to the expected revenue stream, particularly for high variable cost generation.	Same as Option 1, but with less concerns about blocking potential for trying out technological developments and creating administrative effort for small installations. Especially as regards small installations, this could however result in significant loss of market efficiency if large shares of consumption were to be covered by small installations.	Legal clarity to ensure full compensation and non-discriminatory curtailment may be challenging to establish. Unless full compensation and non-discrimination is ensured, priority grid access may remain necessary also after the abolishment of priority dispatch.
Most suitable option(s): Option 3. Abolishing priority dispatch and access exposes generators to market signals from which they have so far been shielded, and requires all generators to actively participate in the market. This requires clear and transparent rules for their market participation, in order to limit increases in capital costs and ensure a level playing field. This should be combined with Option 2: while aggregation can reduce administrative efforts related thereto, it is currently not yet sufficently developed to ensure also very small generators and/or emerging technologies could be active on a fully level playing field; they should thus be able to benefit from continuing exemptions.				

1.1.2. *Description of the baseline*

Dispatch rules determine which power generation facilities shall generate power at which time of the day. In principle, this is based on the so-called merit order, which means that those power plants which for a given time period require the lowest payment to generate electricity are called upon to generate electricity. This is determined by the day-ahead and intraday markets. In most Member States, dispatch is then first decided by market results and, where system stability requires intervention, corrected by the TSO (so-called self-dispatch systems). In some Member States (e.g. Poland) the TSO integrates both steps, directly determining on the basis of the system capabilities and market offers made which offers can be accepted (so-called central dispatch).

Access rules determine which generator gets, in case of congestion on a particular grid element, access to the electricity network. They thus do not relate to the initial network connection, but to the allocation of capacity in situations where the network is unable to fully accommodate the market result. Priority access can thus mean that in situations of congestion, instead of applying the most efficient way of remedying a particular network issue, the transmission system operator has to opt for less efficient, more complex and/or more costly options, to maintain full generation from the priority power plant.

Currently, several Directives allow the possibility or even set the obligation for Member States to include priority dispatch and priority grid access of certain technologies in their national legislation:

- Article 15(4) of the Electricity Directive provides that Member States may foresee priority dispatch of generation facilities using fuel from indigenous primary energy fuel sources to an extent not exceeding, in any calendar year, 15 % of the overall primary energy necessary to produce the electricity consumed in the Member State concerned;
- Article 16(2)(a) of the Renewable Energies Directive obliges Member States to provide for either priority access or guaranteed access to the grid-system of electricity produced from renewable energy sources;
- Article 16(2)(c) of the Renewable Energies Directive obliges Member States to ensure that when dispatching electricity generating installations, transmission system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria;
- Similarly to the provisions under the Renewable Energies Directive, Article 15 (5) b) and c) of the Energy Efficiency Directive foresee priority grid access and priority dispatch of electricity from high-efficiency cogeneration respectively.

The introduction of priority dispatch and priority access for renewable energies on the one hand and for CHP on the other hand are closely related. According to the impact assessment of the Energy Efficiency Directive, Article 15 (5) aims at ensuring a level playing field in electricity markets and help distributed CHP. Thus, the obligation of priority dispatch, and the right to priority access, already existing under its predecessor, Directive 2004/8/EC, have been expanded in the Energy Efficiency Directive to include mandatory priority access for CHP[1]. The new provision fully mirrored the provision under the then new Renewable Energies Directive.

Already for Directive 2004/8/EC, priority dispatch and (the right for a Member State to foresee) priority access were based on the "need to ensure a level playing field" and the challenges for CHP being similar to those for renewable energies. The provision of priority dispatch and priority access for CHP has thus since its beginning been closely related to the provision of these rights to renewable energies. This is also reflected in the text of Article 15(5) itself, which provides that "w*hen providing priority access or dispatch for high-efficiency cogeneration, Member States may set rankings as between, and within different types of, renewable energy and high-efficiency cogeneration and shall in any case ensure that priority access or dispatch for energy from variable renewable energy sources is not hampered.*"

The current framework thus provides that the provision of priority dispatch and priority access for CHP shall under no circumstance endanger the expansion of renewable energies. Against this background, any change to the framework for renewable energies would directly impact the justification underlying the introduction of priority dispatch and priority access for CHP.

The degree to which Member States have made use of the right under Article 15 (4) of the Electricity Directive differs significantly. Some Member States make no use of it whereas other Member States provide for priority dispatch of power generation facilities using national resources (most notably coal). The provisions in the Renewable Energy Directive and Energy Efficiency Directive are mandatory and in principle applied in all Member States, although the implementation can differ significantly due to differences in national subsidy schemes.

1.1.3. *Deficiencies of the current legislation*

European legislation allows the option (as regards indigenous resources) or sets an obligation (for RES E and CHP) to implement priority dispatch and (for RES E and CHP) priority grid access. This creates a framework with very high predictability of the total power generation per year, thus increasing investment security. In particular in view of the increasing share of RES E, this has resulted in a situation where in some Member States very high shares of power generation are coming from "prioritized" sources.

The EU has committed to a continued increase of the share of renewable generation for the coming decades. Until 2030, at least 27 % of final energy consumption in the EU shall come from RES E – this requires a share of at least 45 % in power generation[2]. According to the PRIMES EuCo27 scenario, decarbonisation of EU's energy system would require a share of RES in power generation of close to 50%, wind and solar energy alone projected to cover 29 % of power generation.

[1] https://ec.europa.eu/energy/sites/ener/files/documents/sec_2011_0779_impact_assessment.pdf, p.58.
[2] 2030 Communication, COM(2014) 15 final, p.6.

Today, investments in renewable generation make up the largest share of investments; many RES E technologies can no longer be treated as marginal or emerging technologies.

The comparison of Germany and Denmark, two Member States with high shares both of RES E and CHP, is helpful to assess the deficiencies of systems based on strong priority dispatch and priority access principles. Taking the example of Denmark, an average of 62 % of power demand in the month of January 2014 has come from wind generation alone[3] and the share of annual demand covered by wind power has risen from 19 % in 2009 to 42 % in 2015[4]. Adding to this the share of 50.6 % of CHP in total Danish power generation[5], which makes Denmark one of the Member States with the highest share of CHP[6], in many periods almost all generation would be subject to "priority dispatch". Finally, it may be necessary to add certain generation assets which are needed to operate for system security, e.g. because only they can provide certain system services (e.g. voltage control, spinning reserves), further limiting the scope for fully market based generation. However, in Denmark, market incentives on generators are set in a way that drastically reduces the impact of priority dispatch. Almost all decentralized CHP plants and a large number of wind turbines would be exposed to and are not willing to run at negative prices. As CHP are not shielded from market signals by national support systems, they have strong incentives to stop electricity generation in times of oversupply. The integration of a high share of RES E and CHP in parallel has been successful to a significant extent because CHP are *not* built and operated on the basis of a "must run" model, where heat demand steers electricity generation. To the contrary, CHP plants have back-up solutions (boilers, heat storage), and use these where this is more efficient for the electricity system as expressed by wholesale prices.

Taking the example of another "renewables front runner", Germany, "must run" conventional power plants have been found to contribute significantly to negative prices in hours of high renewable generation and low load, with at least 20 GW of conventional generation still active even at significantly negative prices[7]. Financial incentives are so that many conventional plants generate even at significantly negative prices, with many power plants switching off electricity generation only at prices around minus 60 EUR/MWh. This increases the occurrence of negative prices, worsening the financial outlook for both renewable and conventional generators, and can increase system stress and costs of interventions by the system operator. This is not due to technical reasons – also in Germany, CHP plants generally have back-up heat capacities, which are already necessary to address e.g. maintenance periods of the main plant, or could technically install these. While it may be economically and environmentally efficient to run through short periods of low prices (to avoid ramping up or down), this is no longer the case

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3 http://www.martinot.info/renewables2050/how-is-denmark-integrating-and-balancing-renewable-energy-today.

4 http://www.energinet.dk/EN/El/Nyheder/Sider/Dansk-vindstroem-slaar-igen-rekord-42-procent.aspx.

5 https://ec.europa.eu/energy/sites/ener/files/documents/PocketBook_ENERGY_2015%20PDF%20final.pdf, p. 183.

6 http://www.code2-project.eu/wp-content/uploads/Code-2-D5-1-Final-non-pilor-Roadmap-Denmark_f2.pdf;

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

where the market is willing to pay a lot for electricity being *not* generated. Excess electricity is in these situations not very efficiently generated, but essentially a waste product. While there is a wide range of reasons for conventional generation to produce at hours of negative prices (e.g. very inflexible technologies such as nuclear or lignite which need a long time to reactivate), approximately 50 % of the plants in such a situation in Germany had at least the capability for parallel heat production, and approximately 8-10 % of conventional plants still producing at such moments were found to be heat-controlled CHP generation[8].

In view of the EU target for at least 27 % of renewable energies in final energy consumption (which according to PRIMES EuCo27 projections would require 47 % of gross final electricity consumption to come from renewable energy), the high share of priority dispatch and priority access-technologies will increasingly occur in other Member States. This can have very significant impact on the well-functioning of the electricity market. In particular:

- Subsidy schemes based on priority dispatch (such as Feed-in Tariffs) often are based on high running hours and a mitigation of market signals to the subsidized generator. This means that non-subsidized generation is increasingly pushed out of the market even where this is not cost-efficient;
- Situations in which more than 100 % of demand is covered by priority dispatch become more prevalent. This lowers the investment security provided by priority dispatch, and can lead to results contrary to policy interests such as unnecessary curtailment of RES E;
- The internal energy market depends on steering the use of generation by price signals. In a situation where the clear majority of power generation does not react to price signals, market integration fails and market signals cannot develop;
- Incentives to invest into increased flexibility which would naturally result from price signals on a functioning wholesale market do not reach a significant part of the generation mix. Priority dispatch rules can eliminate incentives for flexible generation (e.g. biomass, some CHP with back-up installations) to use the flexibility potential and instead create incentives to run independent of market demand;
- Priority dispatch and priority grid access limit the choice for transmission system operators to intervene in the system (e.g. in case of congestion on certain parts of the electricity grid). This can result in less efficient interventions (e.g. re-dispatching power plants in suboptimal locations). The increased complexity with high shares of priority dispatch could also lower system stability, although emergency measures may also affect generation benefiting from priority dispatch;
- Priority dispatch rules for high marginal cost technologies can result in using costly primary ressources to generate electricity at a time where other, cheaper, technologies were available;

[8] Consentec, *"Konventionelle Mindesterzeugung – Einordnung, aktueller Stand und perspektivische Behandlung"*, Abschlussbericht 25. Januar 2016, p. vii and 25.

- Priority dispatch rules for generation installations using indigenous ressources result in clear discrimination of cross-border flows and distortions to the internal market.

Against this background, the provision of priority dispatch and priority grid access needs to be reassessed in view of the main policy objectives of sustainability, security of supply and competitiveness (see also Section 7.4.2 of the evaluation).

1.1.4. *Presentation of the options*

For the operation of generation assets, it is recognized that the wholesale market with merit-order based dispatch and access ensures an optimal use of generation resources. Especially in balancing, it also ensures optimal use of congested network capacities. Rules which deviate from these provisions reduce system efficiency and result in market distortions, as it can sometimes be economically more efficient to curtail RES and the guarantee of non-curtailment significantly increases price volatility[9]. Where financial compensation on market-based principles is foreseen in case of re-dispatch, priority dispatch also does not appear to be necessary to mitigate investor risk in low marginal cost technologies. Thus, it is proposed to abolish or at least significantly limit the exceptions foreseen under EU law from merit-order based dispatch and network access.

Option 0: do nothing

This option does not change the legislative framework. Priority dispatch and access provisions remain unchanged in EU legislation and the above-described problems persist.

Option 0+: Non-regulatory approach

Stronger enforcement would not adress the policy objectives. In fact, as the objective is to ensure market-based use of generation assets with limited exceptions, stricter enforcement of existing obligations under EU law which make those exceptions mandatory would be counter-productive.

Voluntary cooperation does not change the legislative framework and thus maintains the currently existing obligations. The order of dispatch for power plants and access to the grid has clear cross-border implications. Priority dispatch/access often results in lower availability of cross-border capacities, and significant differences in these rules can thus distort cross-border trade.

Option 1: Abolish priority dispatch and priority access

Under this option, priority dispatch / priority access provisions would be removed from EU legislation, and replaced by a general principle that generation and demand response shall be dispatched on the basis of using the most efficient resources available, as determined on the basis of merit order and system capabilities.

9 KEMA study commissioned for the EU Commission (ENER/C1/427-2010, Final report of 12 June 2014), p.183 f.

This option would optimally achieve the defined objectives and thus be highly effective. It would however result in additional administrative impact for very small RES E installations which are currently not capable of controlling their feed-in into the grid (notably rooftop solar) and micro-CHP installations. Furthermore, it could increase complexity and prolong the development time for emerging technologies. As these technologies would not yet be mature they would not be able to generate at competitive prices and could thus not reach a number of running hours needed to generate sufficient experience.

Option 2: Limit priority dispatch and/or priority access to emerging technologies and/or small plants

Under this option, priority shall be given only where it can be justified to enable a certain technology or operating model which is seen as beneficiary under other policy objectives. As regards emerging technologies[10], this could in particular be linked to ensuring that the technologies reach a minimum number of running hours as required to gather experience with the non-mature technology. For particularly small generation installations[11], this could reduce the administrative and technical effort linked to dispatching the power plant for its owner, which may appear disproportionate for certain installations. This being said, the administrative effort can be significantly reduced by ensuring the possibility of aggregation, allowing the joint operation and management of a large number of small plants. To mitigate negative impacts on market functioning, both possible exemptions should be capped to ensure that priority dispatch and priority access does not apply to large parts of total power generation.

This option would achieve the defined objectives, although certain trade-offs would be made. Accepting priority dispatch and access for certain installations would reduce market efficiency. If the share of exempted installations in the total electricity market remains low, the negative market impact is however likely to remain very limited. On the other hand, the positive impact of allowing the development of new technologies can provide a significant benefit for the achievement of renewable energy targets in the medium to long-term. Exempting very small installations would also increase public acceptance and reduce administrative efforts required from the operators of these installations, which are often households. This is thus the preferred option, although it has to be ensured that exemptions remain limited to a small part of the market. The exact definition of the emerging technologies could be left to subsidiarity.

Option 3: Abolish priority dispatch and introduce clear curtailment and re-dispatch rules to replace priority access

This option (which can be combined with Option 2) would entail the abolishment of priority dispatch. Priority grid access would be replaced by clear rules on how to deal

[10] In the PRIMES EuCo27 scenario, the emerging technologies of tidal and solar thermal generation (other technologies having insignificant shares) are projected to have a total installed capacity of 7.26 GW and produce 10 TWh of electricity in 2030 (13 GW and 20 TWh in 2050, respectively).

[11] In the PRIMES EuCo27 scenario, RES E small-scale capacity is projected in 2030 to be 85 GW (7.8 % share) and produce 96 TWh of energy (2.9% share).

with situations of system stress, in particular as regards congestion of grid elements. In principle, market-based ressources should be used first, thus curtailing or redispatching first those generators which offer to do this against market-based compensation. In a second step, where no market-based ressources can be used, minimum rules on compensation are foreseen, ensuring compensation based on additional costs or (where this is higher) a high percentage of lost revenues.

It would mean that network operators would obtain a clear incentive to make an assessment on the basis of costs as to the alternatives available to them to address the underlying network constraints, thereby creating opportunities for more innovative solutions such as storage.

The increase in transparency and legal certainty would notably also prevent discrimination against certain technologies (particularly RES E) in curtailment and re-dispatch decisions. RES E are often operated by smaller market players, who could otherwise be subject to excessive curtailment or unable to achieve fully equal compensation. It would also foresee principles on the financial compensation to be paid in case of curtailment or re-dispatch, thus reducing the additional investment risk linked to losing priority access and thereby reducing any increase in capital costs. In order to ensure effective implementation of the new market rules prior to abolishment of priority dispatch and access, priority dispatch and access may be maintained for an interim period after entry into force of the other measures adressing Problem 1.

Increased transparency and legal certainty on curtailment and re-dispatch are a "no regret" measure, in so far as they contribute to market functioning even in the absence of changes to the priority dispatch and priority access framework. Ensuring sufficient compensation for curtailment, notably for RES E, will increase costs to be borne by system operators. In so far as these costs are currently integrated into renewable subsidy schemes, total system costs will however remain similar. As regards priority grid access, this is the preferred option, in order to ensure that the abolishment of priority grid access has no unwanted negative consequences on the financial framework notably of RES E but also of CHP.

1.1.5. *Comparison of the options*

It should be noted that the removal of priority dispatch and priority access does not equally affect different technologies and generators in different Member States:

- The removal of priority dispatch mostly affects high marginal cost technologies (biomass, indigenous resources, some CHP), as low marginal cost technologies (wind, PV) are generally dispatched when available already on the basis of the merit order. Without priority dispatch, high marginal cost technologies thus take up a role more generally associated with other high marginal cost plants, such as gas-fired power plants, operating only in periods of high prices (high residual load). Those generators are then incentivized to making best use of the inherent flexibility that their technology can provide to a power system, and thus accompany the change to an electricity system with a high share of variable low marginal cost generation. For high marginal cost generation, removal of priority dispatch can significantly reduce the number of running hours. Studies for the Commission have shown a reduction of approximately 85 % in dispatch of wood-based biomass generation, mostly to the benefit of gas-fired power plants[12]. To the contrary, there is a (more limited) increase in the running hours of low marginal cost generation, including wind and solar;

- The reduction in inefficient biomass dispatch would represent a major part of the significant reductions of system costs presented in Figure 1 below, with annual savings of 5.9 billion Euros, expected by the removal of market distortions under Problem Area I, Option (1a) of the impact assessment[13];

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

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

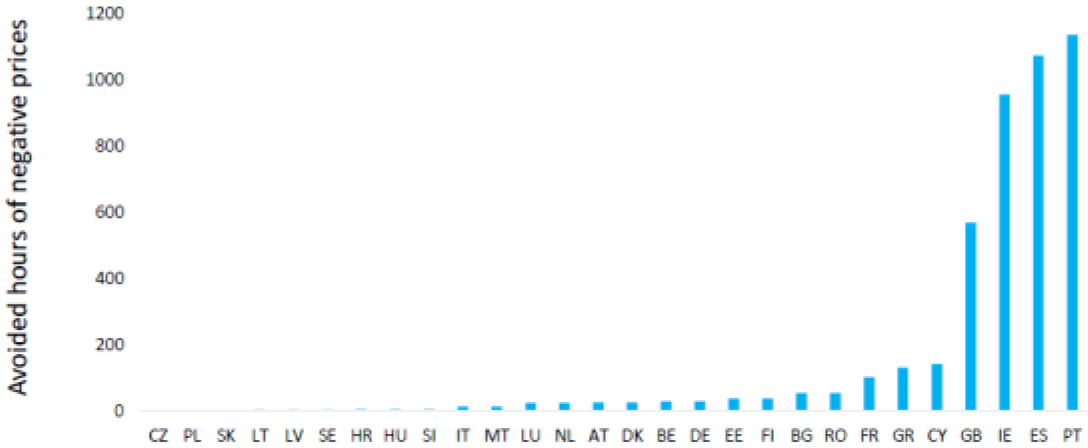
Source: METIS

- By achieving market-based dispatch, the removal of priority dispatch for all technologies drastically reduces the occurrence of negative prices. Whereas negative prices can be a normal occurrence in well-functioning markets which have opportunity costs linked to not offering a service (as is the case on the electricity markets), the occurrence of negative prices based on priority rules shows that priority is given also in times where the system does not require additional generation.

[12] For this assessment, biomass was assumed to consist of 22 % "must-run" waste incineration (OPEX: 3.6 EUR EUR/MWh) and 78 % wood-fired plants with high variable costs (around 90 EUR EUR/MWh)

[13] For more details please see Section 6.1.2 of the impact assessment.

Figure 2: reduction of negative price occurrences by removal of priority dispatch



Source: METIS

- The removal of priority access on the other hand mostly affects technologies which are producing in areas and at times of network congestion. This will more often concern low marginal cost technologies (especially wind) as periods of high wind feed in are more likely to result in congested network elements, requiring curtailment or re-dispatch;
- Providing clear and transparent rules on curtailment and compensation benefits all market actors. This is particularly true for small and/or new market actors, including RES E;
- While the change of biomass dispatch to reflect its role as flexible back-up generation, to the benefit mostly of gas, but also of coal and nuclear generation thus would drastically reduce future system costs, it could possible entail an increase of CO2 emissions in the power sector, whereas total CO2 emissions under the ETS framework would in principle remain identical over time[14].

Option 1 would be the most effective in achieving the objective of non-discrimination and market efficiency. However, it could result in an increase of costs to achieve other policy objectives, notably for decarbonisation of the energy system. Fully removing priority dispatch and access would also result in an increased need for small generators, including households (e.g. rooftop solar) to participate in the electricity market. While this would allow strong economic incentives, it would thus increase the administrative impact for households and SMEs. Thus, clear and transparent rules for the market participation of RES E and CHP as well as limited exemptions for small and emerging technologies should be included, to accompany the phase-out of priority access and priority dispatch. On the other hand, remaining at the *status quo* would, with a growing share of priority technologies in the system, seriously undermine effective price formation and dispatch in the wholesale market. The preferred option is thus a

[14] The environmental impacts from the removal of priority dispatch for biomass are discussed in Section 6.1.6 of the impact assessment

combination of Options 2 and 3. This will allow a reduction of the administrative impact for households and SMEs while ensuring the most efficient use of bigger mature power generators.

1.1.6. *Subsidiarity*

Priority dispatch is foreseen directly in EU law. Changing or removing those provisions cannot be achieved on a national level. Furthermore, in an integrated electricity market, the way to determine which power plant is operated has a direct impact on cross-border trade. Applying discriminatory provisions for power plant dispatch in certain Member States can thus negatively affect cross-border trade or even directly result in discrimination against power generators in other Member States. Ensuring efficient market integration and functioning investment signals, requires fundamental dispatch rules to be harmonized.

1.1.7. *Stakeholders' opinions*

In the public consultation, most stakeholders support the full integration of Renewable energy sources into the market, e.g. through full balancing obligations for renewables, phasing-out priority dispatch and removing subsidies during negative price periods. Many stakeholders note that the regulatory framework should enable RES E to participate in the market, e.g. by adapting gate closure times and aligning product specifications. A number of respondents also underline the need to support the development of aggregators by removing obstacles for their activity to allow full market participation of renewables.

Also stakeholders from the renewable sector often recognize the need to review the priority dispatch framework. They make this however subject to conditions; Wind Europe provided views on curtailment of wind power and priority dispatch and stated that "*countries with well integrated day-ahead, intraday and balancing market and a good level of interconnections, where priority of dispatch is not granted to CHP and conventional generators, do not need to apply priority of dispatch for wind power."* They argue that "*in general, priority dispatch should be set according to market maturity and liberalisation levels in the Member State concerned, but also taking due account of progress in grid developments and application of best practices in system operation*." According to its paper from June 2016 on curtailment and priority dispatch, in the view of Wind Europe[15], some EU markets, such as Sweden and the UK, which have relatively high penetration rates of wind, do not offer priority dispatch for wind producers[16] and this does not place any restrictions on market growth. However, a phase-out of priority dispatch for renewable energies should only be considered if (i) this is done also for all other forms of power generation, (ii) liquid intraday markets with gate closure near real-time, (iii) balancing markets allow for a competitive participation of wind producers; (short gate closure time, separate up/downwards products, etc.), and (iv) curtailment rules

15 https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Priority-Dispatch-and-Curtailment.pdf.

16 The Commission services interpret this to mean that, while priority dispatch may be foreseen under national legislation, it has no practical impact.

and congestion management are transparent to all market parties. According to Wind Europe, these requirements are already in 2016 fulfilled in certain markets such as the UK, Sweden and Denmark, whereas other Markets currently still required priority dispatch. It is the view of the Commission services that by entry into force of the present legislative initiative, the above requirements are met in all Member States.

Regarding priority access, Wind Europe asks for curtailments to be valued by the market as a service to ensure system security. It should be treated as downward capacity and its price should be set via the balancing market. This would already be applied in the Danish and UK markets. Participation of wind in the balancing markets could lead to a significant reduction of curtailments. This is taken into account in Option 3, which ensures the primary use of available market-based ressources prior to any non-market based curtailment. Where balancing ressources are available, including from RES E, and capable of adressing the system problem underlying the planned curtailment, they thus have to be used before non-market based curtailment takes place. For this second step, transparent compensation rules are foreseen. Wind Europe recognizes that *"there may be a benefit from not compensating 100% of the opportunity cost. Reducing slightly the income could send an important incentive signal to investors to select locations with existing sufficient network capacity, Curtailment would then be likely to occur less frequently. The exact % of the opportunity cost needs to be carefully assessed in order to find a balance between an increase in policy cost and the increase of financing costs due to higher market risk."* This position is reflected in the present proposal.

Stakeholders from the cogeneration sector underline the link to priority dispatch for renewable energies. COGEN Europe submits that it is "*important that at EU level CHP benefits from at least parity with RES on electricity provisions, as long as there are no additional policy measures that would compensate for the loss in optimal operation ensured through priority of dispatch for certain types of CHPs."* They also argue that "*while a significant fraction of the CHP fleet can be designed and/or retrofitted to operate in a more flexible way (e.g. though partial load capabilities, enhanced design from the electrical components, and the heat storage addition), this may come at the expense of the site efficiency and industrial productivity.*" The parallelism to RES is maintained in all options, whereas the additional costs and possible loss of efficiency have to be balanced with the economic cost of significant amounts of inflexible conventional generation in a high-RES system.

EUROBAT, association of European Manufacturers of automotive, industrial and energy storage batteries, regards curtailing of energy as a system failure, as the "wasted" power should be stored in batteries instead. It argues against any financial compensation to renewable generators for being curtailed, as such a compensation would disincentivize the installation of energy storage systems[17].

Transmission system operators would be directly affected, as they are responsible for practical implementation of the priority rules. In May 2016, ENTSO-E has asked their Members to provide answers to questions which had been discussed with the

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[17] http://www.eurobat.org/sites/default/files/eurobat_batteryenergystorage_web.pdf p.28.

Commission services. 29 TSOs from 25 countries have replied, though not all TSOs answered all questions, which is also due to the limited impact of priority dispatch/access in some Member States (with a low share of CHP and RES E). TSOs from 14 Member States answered that priority dispatch increases the costs of pursuing stable, secure and reliable system operations. TSOs from a smaller group of Member States (4 to 6) also stated that priority dispatch limits the possibilities to keep the grid stable, secure and reliable. Only the TSOs of three Member States answered that priority dispatch has no major effect on system operations. Regarding the market impact, TSOs from 12 Member States raised increased dispatching costs and 9 raised the occurrence of negative prices. On the other hand, TSOs from one Member State argued that priority dispatch resulted in reduced costs for the support of RES E. TSOs also stressed the cross-border impact of priority dispatch: TSOs from 6 Member States referred to increased congestion of interconnectors, and an example provided was that priority dispatch in neighbouring areas impacted the system operation in the TSOs area. When asked how European legislation should adress the issues mentioned, no TSO wanted to retain priority dispatch, 8 TSOs wanted to retain it with exemptions, 4 TSOs wanted a phase out of priority dispatch, and 13 TSOs wanted priority dispatch to be removed entirely.

16 Priority access and dispatch

1.2. Regulatory exemptions from balancing responsibility

1.2.1. *Summary table*

Objective: To ensure that all technologies can compete on an equal footing, eliminating provisions which create market distortions unless clear necessity is demonstrated, thus ensuring that the most efficient option for meeting the policy objectives is found. Each entity selling electricity on the market should be responsible for imbalances caused.				
	Option 0	Option 1	Option 2	Option 3
Description	Do nothing. This would maintain the *status quo*, expressly requiring financial balancing responsibility only under the State aid guidelines which allow for some exceptions.	Full balancing responsibility for all parties Each entity selling electricity on the market has to be a balancing responsible party and pay for imbalances caused.	Balancing responsibility with exemption possibilities for emerging technologies and/or small installations This would build on the EEAG.	Balancing responsibility, but possibility to delegate This would allow market parties to delegate the balancing responsibility to third parties. This option can be combined with the other options.
Pros	Lowest political resistance	Costs get allocated to those causing them. By creating incentives to be balanced, system stability is increased and the need for reserves and TSO interventions gets reduced. Incentives to improve e.g. weather forecasts are created.	This could allow shielding emerging technologies or small installations from the technical and administrative effort and financial risk related to balancing responsibility.	The impact of this option would depend on the scope and conditions of this delegation. A delegation on the basis of private agreements, with full financial compensation to the party accepting the balancing responsibility (e.g. an aggregator) generally keeps incentives intact.
Cons		Financial risks resulting from the operation of variable power generation (notably wind and solar power) are increased.	Shielding from balancing responsibilities creates serious concerns that wrong incentives reduce system stability and endanger market functioning. It can increase reserve needs, the costs of which are partly socialized. This is particularly relevant if those exemptions cover a significant part of the market (e.g. a high number of small RES E generators).	The impact of this option would depend on the scope and conditions of this delegation. A full and non-compensated delegation of risks e.g. to a regulated entity or the incumbent effectively eliminates the necessary incentives. Delegation to the incumbent also results in further increases to market dominance.
Most suitable option(s): Option 2 combined with the possibility for delegation based on freely negotiated agreements.				

1.2.2. *Description of the baseline*

Balancing responsibility refers to the obligation of market actors (notably power generators, demand response providers, suppliers, traders and aggregators) to deliver/consumer exactly as much power as the sum of what they have sold and/or purchased on the electricity market. Predictions for demand and (to a more limited extent) generation being not 100 % precise, market actors are often not fully balanced. The Transmission System Operator then ensures that total demand and supply are maintained in balance by activating (upward or downward) balancing energy, often coming from dedicated balancing capacities.

Balancing responsibility implies that the costs of the balancing actions taken by the transmission system operator are generally to be compensated by the market parties which are in imbalance. In some Member States, certain types of power generation (notably wind and solar, but possibly also other technologies such as biomass) are excluded from this obligation or have a differentiated treatment. Most Member States foresee some degree of balancing responsibility also for renewable generators; based on an EWEA (now Wind Europe) study, in 14 out of 18 Member States with a wind power share above 2-3 % in annual generation, wind generators had some form of balancing responsibility[18]. This however does not always translate into real financial responsibility of the generator for imbalances it caused. In Austria for example, a public entity, OEMAG, acts as balancing responsible party for all subzidized renewable generation, thus shielding individual generators from imbalance risks of their power plants[19] and collectively purchasing/selling balancing energy for the renewable sector[20]. On the other hand, in a small number of Member States balancing costs imposed on renewable power generation can be prohibitively high and almost reach the level of wholesale prices (e.g. incurred balancing costs of up to 24 EUR/MWh in Bulgaria and 8-10 EUR/MWh in Romania)[21].

Article 28 (2) of the Balancing Guideline provides that *"each balance responsible party shall be financially responsible for the imbalance to be settled with the connecting TSO"*. This does not, however, preclude frameworks in which market actors are (fully or partly) shielded from the financial consequences of imbalances caused by having this responsibility shifted to another entity. This is part of some current support schemes.

The EEAG provide that in order for State aid to be justified, RES E generators need to bear full balancing responsibility unless no liquid intra-day market exists. The EEAG rules however do not apply where no liquid intraday market exists, and and also do not apply to installations with an installed electricity capacity of less than 500 kW or

18 http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA-position-paper-balancing-responsibility-and-costs.pdf, p. 5-6.

19 https://www.energy-community.org/portal/page/portal/ENC_HOME/DOCS/2014187/0633975ACF8E7B9CE053C92FA8C06338.PDF

20 http://www.oem-ag.at/de/oekostromneu/ausgleichsenergie/.

21 http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA-position-paper-balancing-responsibility-and-costs.pdf p. 8.

demonstration projects, except for electricity from wind energy where an installed electricity capacity of 3 MW or 3 generation units applies. The exemption from balancing responsibility in the absence of liquid intra-day markets is based on the reasoning that were liquid intra-day markets *do* exist, they allow renewable generators to drastically reduce their imbalances by trading electricity on short-term markets and thus taking account of updated wheather forecasts. This shows that imposition of balancing responsibility is thus closely linked to the creation of liquid short-term markets, one of the main objectives of the electricity market design initiative.

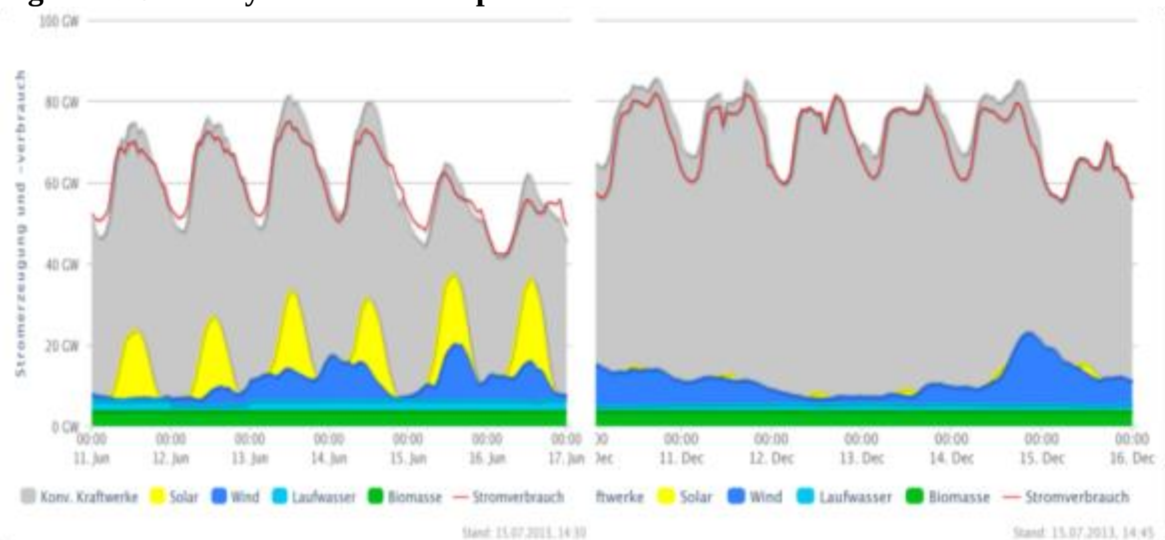
The corollary to balancing responsibility is the possibility to participate in the balancing market, offering balancing capacity to the TSO against remuneration. This is further described under Section 5.1.1.4 and closely linked to the Balancing Guideline.

1.2.3. *Deficiencies of the current legislation*

Already today, the increased share of renewable energies in power generation (approximately 29% in 2015) has significant impact on market functioning and grid operation. This effect is most noticeable in Member States with RES E shares above the EU average.

The below figure shows two relevant weeks, with production and consumption shown together. In the left graph, generation exceeds the load (red line) in situation with lots of solar power generation (yellow). In the right graph, less renewable power is generated (blue, green, yellow, but minimal PV (yellow)). Supply and demand of electricity has to match at all times despite changes in demand and variable renewable electricity production. For both situations, flexibility options such as storage, demand side response, flexible generation and interconnection import/export capacities are needed to take up electricity.

Figure 1: Volatility in the German power market in June and December 2013



Source: Agora Energiewende 2013.

To integrate renewable production progressively and efficiently into a market that promotes competitive renewables and drives innovation, energy markets and grids have to be fit for renewables. This is not necessarily the case in many jurisdictions since markets have traditionally been designed to cater the needs of conventional generation rather than variable renewables. To make markets fit for renewables means developing adequately the short-term markets such as intraday and balancing. This also means allowing, to the maximum possible extent, renewables to participate in all electricity markets on equal footing to conventional generation removing all existing barriers for renewable energy sources integration. Integrating RES E into the market and allowing them to generate a large part of their revenues from market prices requires an increase of flexibility in the system, which is also needed for absorbing cheap renewable electricity at times of high supply. It is for this reason that the EEAG (para.124) requires generators to be subject to standard balancing responsibilities only unless no liquid intra-day market exists. Liquid intra-day markets should exist in all Member States at the expected date of entry into force of the revised legislation, accompanying the present impact assessment. However, the term "liquid intra-day market" allows significant margin of interpretation and can thus cause uncertainty on the application of one of the fundamental rules on the electricity market. It will be necessary to further clarify this exemption and ensure that market actors have legal certainty as to whether they have to bear balancing responsibility or not.

Investment incentives should take into account the value of generation at different times of the day or of the year. Progress has been made in this area, with support schemes relying increasingly (but not everywhere or for all generation) on premiums instead of fixed feed-in tariffs. Where premium-based support schemes are used, the degree of market exposure depends on their exact implementation, differing e.g. between fixed and floating premium models, and for the latter relative to the determination of the base price used for the calculation of the premium. Full exposure to market signals may e.g. make a different generation installation more efficient although it produces lower total output (such as orienting PV to the west to increase output later in the day). By exposing generators to the financial consequences of imbalances caused, the incentives given to generators do not relate only to optimizing the expected generation of their power plant in view of market needs, but also to ensuring that the electricity they sell on the market matches as closely as possible the power produced at a certain point in time. In a questionnaire to TSOs organized by ENTSO-E, the example was given that following the attribution of balancing responsibility in a Member State, the average hourly imbalance of PV installations improved from 11.2 % in 2010 to 7.0 % in March 2016, and the average hourly imbalance of wind improved from 11.1 % to 7.4 % over the same period.

Where RES E generators do not assume balance responsibility identical to other generators and participate in the balancing market, they lack incentives for efficient operational and investment decisions[22]. Part of this challenge is the need to avoid inacceptable risks for RES E investors by imposing balance responsibilities without

[22] KEMA study commissioned for the EU Commission (ENER/C1/427-2010, Final report of 12 June 2014), p.185

creating the market flexibility which allows staying balanced[23]. Whereas many Member States already foresee some balancing responsibility for RES E generators (2013: 16 Member States)[24] this is not yet the case for all Member States, and the degree of balancing responsibility differs considerably between Member States. This can result in market distortions, directing investments to Member States with lower degree of responsibility rather than to those Member States where electricity demand and renewable generation potential are optimal, and can also result in lower liquidity of short-term markets.

Reduced balancing responsibility can also result in increasing imbalances in electricity trades. Whereas the TSO will generally, via the balancing market, be capable of covering imbalances, a high degree of imbalances reduces predictability of system operation and can increase system stress (e.g. by reducing the volume of available reserves) or increase costs for system stability (e.g. if higher reserve volumes are procured in advance).

Finally, it should be noted that the EEAG already foresees the need to phase out exemptions from balancing responsibilities in the post-2020 period[25]. The EEAG itself provides in its paragraph 108 that the Guidelines *"apply to the period up to 2020 but should prepare the ground for achieving the objectives set in the 2030 framework, implying that subsidies and exemptions from balancing responsibilities should be phased out in a degressive way"*.

Refrence is also made to Section 7.4.2 of the evaluation.

1.2.4. *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

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23 KEMA p. 185: *"Experience from some EU countries has shown that RES generators are able to provide less volatile and more predictable generation schedules if so incentivized by balancing arrangements."*

24 http://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd04_en.pdf Appendix I table 6.

25 Paragraph 108 EEAG reads: "*These Guidelines apply to the period up to 2020. However, they should prepare the ground for achieving the objectives set in the 2030 Framework. Notably, it is expected that in the period between 2020 and 2030 established renewable energy sources will become grid-competitive, implying that subsidies and exemptions from balancing responsibilities should be phased out in a degressive way. These Guidelines are consistent with that objective and will ensure the transition to a cost-effective delivery through market-based mechanisms.*"

half of 2016. General principles and, where applicable, exemptions shall be integrated into the Electricity Directive for added clarity and legal certainty.

Option 0: do nothing

This would mean that balancing responsibility remains subject only to State aid rules and the rules in the Balancing Guideline. Fundamental principles of electricity market operation should systematically not be decided upon only in acts adopted under the Comitology process and guidelines which undergo no legislative process. Furthermore, the EEAG are limited in time to 2020 and uncertainty as to the extent of their exemptions and their applicability post-2020 will persist. According to their paragraph 108, it is expected that in the period between 2020 and 2030 established renewable energy sources will become grid-competitive, implying that subsidies and exemptions from balancing responsibilities should be phased out in a progressive way (and thus assuming liquid short-term markets to develop). Finally The State aid guidelines only apply to those parts of measures which are to be seen as State aid. This concerns most, but not necessarily all, generation which may not be fully balancing responsible. For some aspects the qualification as State aid could potentially be put into question.

Option 0+: Non-regulatory approach

As national law is extremely varied to date, without a clear and transparent framework setting out the degree of balancing responsibility, enforcement of existing rules (e.g. State aid rules) is unlikely to result in a uniform and non-discriminatory legal framework.

Voluntary cooperation can contribute to reducing the negative impact of imbalances. Imbalance netting by transmission system operators already achieves significant cost reductions. However, voluntary cooperation does not provide sufficient legal certainty and the minimum degree of harmonization to avoid distortions in cross-border trade. In fact, shielding certain market parties fully or in part from balancing responsibilities creates economic advantages which can distort cross-border trade in electricity. Where a lack of balancing responsibility results in increased imbalances, this will negatively impact the whole synchronous area, and thus create costs and risks for system stability also in other Member States.

Option 1: Full Balancing responsibility for all parties

This would entail that the principles of the Balancing Guideline imposing all market-related entities and their representatives to be financially responsible for imbalances caused would be integrated into the Electricity Directive.

This option would thus significantly increase transparency and legal certainty. Balancing responsibility is already an accepted concept under the EEAG, so that the market impact would be limited to those entities currently benefitting from exemptions or not subject to State aid rules. While this option would optimally achieve the defined objective, the complete abolishment of the existing exemptions could result in increased administrative effort for small installations or demonstration projects using emerging technologies.

Option 2: Balancing responsibility with exemption possibilities for emerging technologies and/or small installations

23
Regulatory exemptions from balancing responsibility

This would allow Member States to foresee that certain emerging technologies and/or small installations (e.g. rooftop solar) are shielded from the direct financial impact of imbalances they cause. As imbalances need to be covered by some entity, this could be achieved by allocating it to public bodies (essentially meaning that these entities are acting as sellers of RES E on the wholesale market), the costs of which are then socialized.

This option addresses the currently existing exemptions under EEAG, based on the assumption that short-term markets have developed sufficiently by the time of entry into force of the proposed legislation to require balancing responsibility of generators not covered by the exemptions. Without introducing additional limitations, these exemptions would however risk reducing effectiveness in achieving the policy objective. This is notably the case for small installations, which under some scenarios can account for a significant part of total electricity supply.

Option 3: Possibility to delegate balancing responsibility

This option would entail the right to delegate balancing responsibilities to a third party. Whereas the freely negotiated delegation to a third party against financial compensation (e.g. an aggregator) can reduce administrative impact without reducing the incentive to reduce imbalances (as their cost will be passed on to the generator in some way), regulated delegations without compensation drastically reduce or eliminate the incentive to remain balanced.

The possibility to delegate on the basis of free negotiation, against financial compensation, (combined with exemptions notably for demonstration projects and possibly very small installations) is the preferred option. It fully achieves the policy objectives, and allows notably smaller installations to reduce administrative efforts without reducing market incentives.

1.2.5. *Comparison of the options*

The requirement of full balancing responsibility does not affect all renewable technologies in the same manner. Biomass and other non-variable technologies are generally capable of being balanced to the same degree as conventional generators. Variable generators (especially wind and PV) can increasingly predict their generation based on wheather forecasts, but have a higher margin of error in those predictions than conventional generators. To reduce the margin of error, those technologies need to improve wheather forecasts, as well as sell electricity for shorter time periods in advance, when better forecasts become available.

A study using METIS has shown very significant reductions in frequency restoration reserve needs due to the introduction of balancing responsibilities for RES E. Whereas FCR and aFRR needs relate to short-term frequency deviations and are thus not significantly affected by balancing responsibility, mFRR needs are based on longer-lasting deviations from indicated schedules. By creating incentives for improved forecasts and more exact schedules, reserve needs are thus significantly reduced.

Figure 2: reduction in reserve needs depending on balancing responsibility

GW		Baseline	Option 1a
FCR + aFRR	Upwards	16.7	16.7
	Downwards	16.2	16.1
mFRR	Upwards	23.5	17.4
	Downwards	23.2	15.6
Total (FCR + FRR)		**79.6**	**65.8**
Reduction		**-**	**17%**

Important impact on mFRR needs (-30%)

Source: METIS

Option 1 would be most effective at achieving the objective of well-functioning markets. All exemptions from balancing responsibility, even if only partly shielding against the financial impact of imbalances, reduce the incentive to be balanced. The complete abolishment of the existing exemptions would however result in increased administrative effort for small installations or demonstration projects using emerging technologies. This could slow down roll-out of new RES E technologies and could thus render the achievement of the decarbonisation objective more costly. Options 2 and 3 can be combined to ensure a maximum degree of balancing responsibility with the potential to delegate this responsibility, which allows reduction of the additional administrative impact imposed especially on small installations. This being said, small installations are currently often not active on the market, and it could be excessive to require balancing responsibility even taking into account the possibility to delegate. The preferred option is thus a derogation from balancing responsibilities for demonstration projects and small generation (e.g. rooftop solar), and the right for other projects to delegate their balancing responsibility against financial compensation. This significantly reduces the administrative effort for households and small and medium enterprises (who will often continue to benefit from exemptions from balancing responsibilities) but takes account of the increased role renewable generation plays in the market, and the improved capabilities particularly of larger generators to predict their output and reduce or hedge remaining imbalance risks.

1.2.6. *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 responsibiltity impacts both investment decisions and trading on electricity markets; every decision to sell electricity on the market entails the risk to be in imbalance, which thus has to be integrated into bidding strategies. Deviations on a national level in an integrated market could result in distortions of cross-border trade, e.g. by making investments into variable generation in one Member State significantly more interesting than in other Member States, and basic principles for balancing responsibility thus need to be harmonized.

Furthermore, increasing the share of RES E in the total energy consumption is an EU target. For 2030, a target binding at EU level exists, without nationally binding targets; therefore the EU has to ensure the EU target is reached. With an increasing share of RES E, they become a relevant player on the power markets. As power markets are increasingly integrated, this has direct cross-border impact. Equal treatment to all generation technologies should be ensured to avoid market distortions. Markets should be fit to allow all generation technologies and demand to compete on equal footing, while allowing the EU to reach the policy objectives of sustainability, competitiveness and security of supply. The increasing share of RES E also creates challenges for network operation. In synchronous areas even exceeding the EU, this is an issue which cannot be resolved at national level alone.

1.2.7. *Stakeholders' opinions*

In the public consultation, most stakeholders support the full integration of renewable energy sources into the market, e.g. through full balancing obligations for renewables, phasing-out priority dispatch and removing subsidies during negative price periods. Many stakeholders note that the regulatory framework should enable RES E to participate in the market, e.g. by adapting gate closure times and aligning product specifications. A number of respondents also underline the need to support the development of aggregators by removing obstacles for their activity to allow full market participation of renewables. The approach chosen in the State aid guidelines found broad support by most stakeholders.

Wind Europe's predecessor EWEA submitted[26] that in 14 out of 18 Member States, wind generators were already balancing responsible in financial or legal terms, generally subject to the same rules as conventional generation. However, in some Member States, balancing costs for renewable generators appeared discriminatorily high. Important considerations for wind generators to accept balancing responsibility were, for EWEA: (i) the existence of a functioning intra-day and balancing market, (ii) balancing market arrangements providing for the participation of wind power generators, as e.g. shorter gate closure time and procurement timeframes, (iii) market mechanisms that properly value the provision of non-frequency ancillary services for all market participants including wind power, (iv) a satisfactory level of market transparency and proper market monitoring, (v) sophisticated forecast methods in place in the power system and (vi) the necessary transmission infrastructure. While forecast methods should be developed by the market and cannot be provided directly in policy (which can only give incentives for

26 http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA-position-paper-balancing-responsibility-and-costs.pdf

such methods to be improved and used), the market design initiative aims at achieving all these points.

In its consultation of national TSOs, ENTSO-E also adressed questions on balancing responsibility. TSOs in five Member States answered that after introduction of balancing responsibilities, RES E generators were more motivated to conclude energy production contracts which are close to the real production in each market time unit; for four Member States, better forecasts were used by RES E generators. 1 TSO provided figures according to which the average hourly imbalance of PV installations improved from 11.2 % in 2010 to 7.0 % in March 2016, and the average hourly imbalance of wind improved from 11.1 % to 7.4 % over the same period.

1.3. RES E access to provision of non-frequency ancillary services

1.3.1. *Summary table*

Objective: transparent, non-discriminatory and market based framework for non-frequency ancillary services		
Option 0	**Option 1**	**Option 2**
BAU Different requirements, awarding procedures and remuneration schemes are currently used across Member States. Rules and procedures are often tailored to conventional generators and do not always abide to transparency, non-discrimination. However increased penetration of RES displaces conventional generation and reduces the supply of these services.	Description Set out EU rules for a transparent, non-discriminatory and market based framework to the provision of non-frequency ancillary services that allows different market players /technology providers to compete on a level playing field.	Description Set out broad guidelines and principles for Member States for the adoption of transparent, non-discriminatory and market based framework to the provision of non-frequency ancillary services.
Stronger enforcement Provisions containing reference to transparency, non-discrimination are contained in the Third Package. However, there is nothing specific to the context of non-frequency ancillary services.	Pro Accelerate adoption in Member States of provisions that facilitate the participation of RES E to ancillary services as technical capabilities of RES E and other new technologies is available, main hurdle is regulatory framework. Clear regulatory landscape can trigger new revenue streams and business models for generation assets.	Pro Sets the general direction and boundaries for Member States without being too prescriptive. Allows gradual phase-in of services based on local/regional needs and best practices.
	Con Resistance from Member States and national authorities/operators due to the local/regional character of non-frequency ancillary services provided. Little previous experience of best practices and unclear how to monitor these services at DSO level where most RES E is connected.	Con Possibility of uneven regulatory and therefore market developments depending on how fast Member States act. This creates uncertain prospects for businesses slowing down RES E penetration.
Most suitable option(s): Option 2 is best suited at the current stage of development of the internal electricity market. Ancillary services are currently procured and sometimes used in very different manners in different Member States, Furthermore, new services are being developped and new market actors (e.g. batteries) are quickly developing. Setting out detailed rules required for full harmonisation would thus preclude unknown future developments in this area, which currently is subject to almost no harmonisation.		

1.3.2. *Description of the baseline*

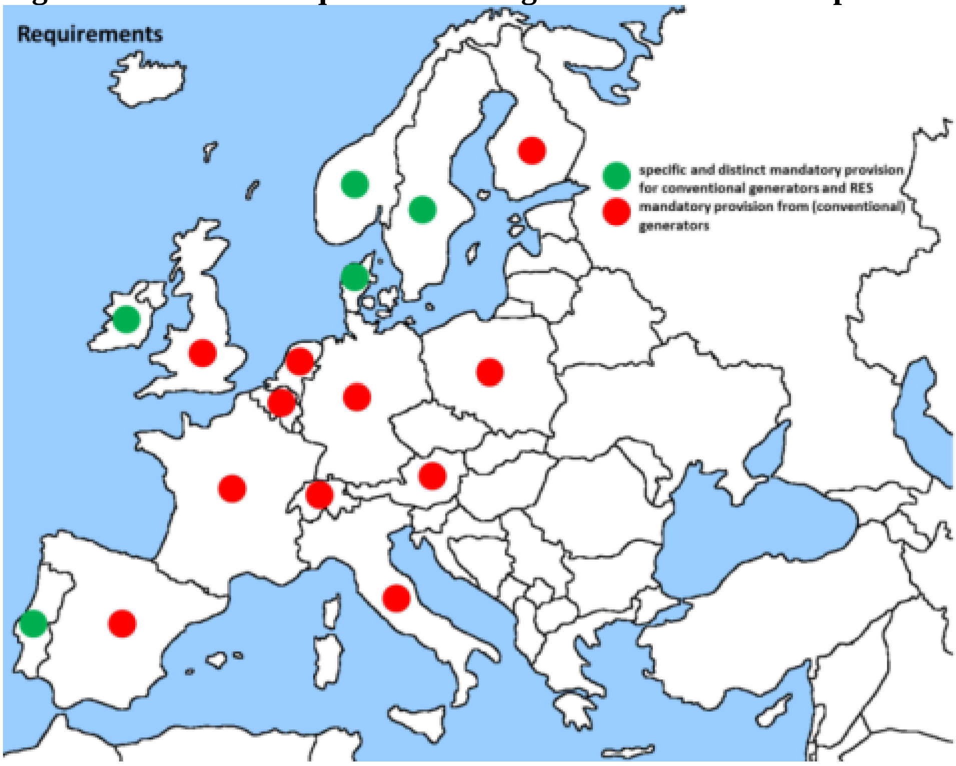
The delivery of **frequency** related ancillary services by RES E assets is partly covered by the Balancing Guideline.

Non-frequency ancillary services are services procured or mandated by TSOs that support the electricity network, such as voltage support, short circuit power, black start capability, synthetic inertia or congestion management. They are in most cases supplied by electricity generators, but can in some cases also be supplied by demand facilities, electricity storage or network equipment.

Currently, the procurement of non-frequency anciliary services is not regulated at EU-level. The situation in Member States for the provision of **non-**frequency ancillary services is determined by national grid codes that *inter alia* specify the rules for connection of generation assets to the electric network infrastructure. Grid codes are evolving continuously, but a snapshot taken recently through studies funded by the European Commission[27], a survey commissioned by ENTSO-E[28] and by examining the actual national grid codes, reveals that several approaches are considered in Europe across more than a dozen Member States (as well as Norway and Switzerland) surveyed. The snapshot, summarized in Figures 1 to 3, focuses only on the provision of reactive power, i.e. voltage related ancillary services, one of the most important non-frequency ancillary services. It is important to point out that the overview is partial and does not cover all specific arrangements TSOs might have. For instance in Denmark, these services are not generally remunerated, however in certain periods of the year when thermal plants are not operating, these services are remunerated to guarantee sufficient supply.

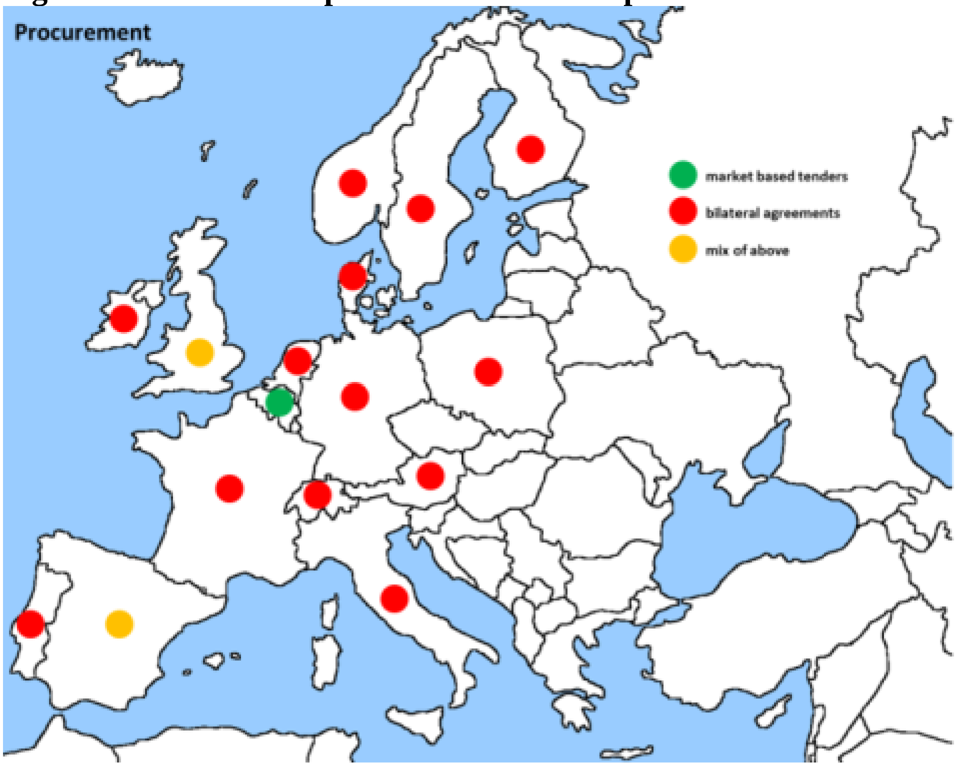
27 *"REserviceS project"* (2014) Intelligent Energy Europe programme, http://www.reservices-project.eu/
28 *"Survey on Ancillary Services Procurement and Electricity Balancing Market Design"* (2015) ENTSO-E, https://www.entsoe.eu/Documents/Publications/Market%20Committee%20publications/WGAS%20Survey_04.05.2016_final_publication_v2.pdf?Web=1

Figure 1: Grid code requirements for generators on reactive power



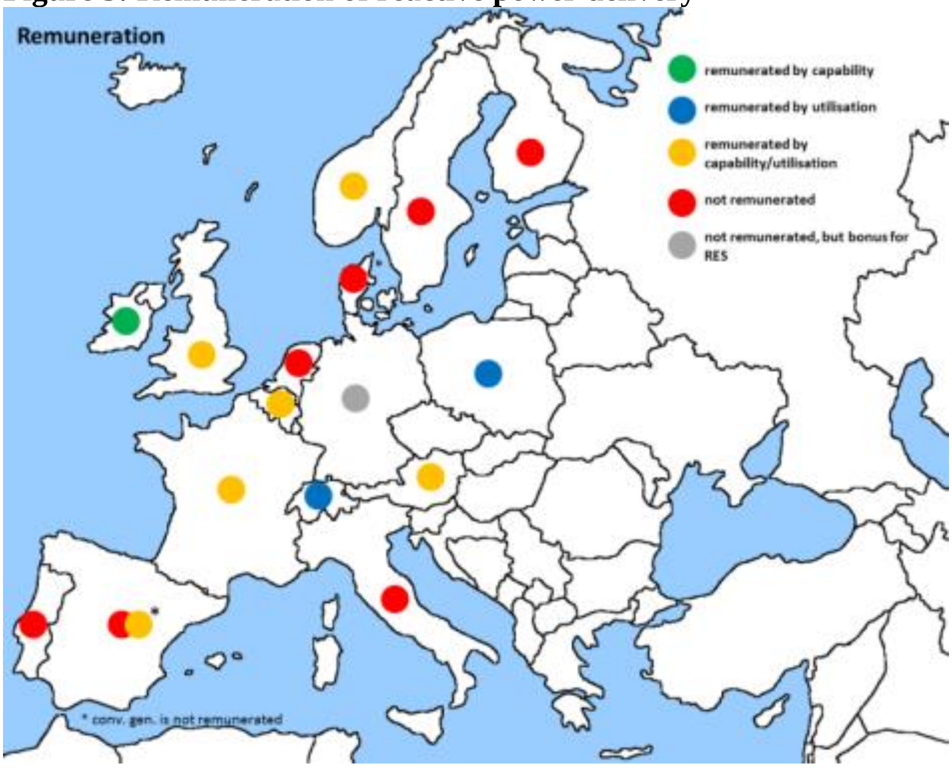
Source: National grid codes, ENTSO-E survey, REserviceS project

Figure 2: Procurement procedure of reactive power



Source: National grid codes, ENTSO-E survey, REserviceS project

Figure 3: Remuneration of reactive power delivery



Source: National grid codes, ENTSO-E survey, REserviceS project

Currently the practises with regard to requirements, procurement and renumeration of non-frequency anciliary services can be summarised as follows:

- Requirements: most Member States demand mandatory provision from conventional generators and in some cases specific provisions are considered for RES E, mostly wind. The latter approach is in line with the Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators ('RfG');
- Procurement: a majority of Member States procure these services through bilateral agreements and only in a small minority of Member States market based tenders are used. In other Member States both bilateral agreements and market based tenders are used;
- Remuneration: about half of the surveyed Member States do not have a mechanism to remunerate the service, the other half does remunerate them either by capability, utilisation or a combination of both. In some Member States, a bonus is given to RES E for upgrading the infrastructure.

1.3.3. *Deficiencies of the current legislation*

The current EU regulatory framework defines in Article 12 lit. d) of the Electricity Directive the role of the TSO: it includes ensuring the availability of all necessary ancillary services. However, there is nothing specific with regard to non-frequency ancillary services. The RfG specifies extensively requirements for the provision of reactive power by different power modules. However, it does neither address the procedures by which such services should be awarded (e.g; a market based mechanism), nor whether they should be remunerated (as such or on the basis of what criteria e.g. capacity, utilisation or a combination thereof). Additionally, the RfG is not likely to lead to an efficient deployment of reactive power capability on the territory as voltage support services have a geographical dimension and need to be provided in specific locations. This might lead to an oversupply of reactive power capability (with associated increased costs born by the generators) and at the same time underutilization of installed capability because they are not suitably located. The System Operation Guideline aims at ensuring that TSOs use market-based mechanisms as far as possible to ensure network security and stability, but does not articulate further this high level principle.

The current legislation is insufficient and needs to be adapted to trends observed in the market where studies project that the demand for non-frequency ancillary services across Europe will increase over the coming decades, mainly because of increased RES E penetration. A technical and economical study by Électricité de France (EDF)[29] concluded that *"it is essential that variable RES production which is displacing conventional generation is also able to contribute to the provision of ancillary services and also potentially provide new services (e.g. inertia)".* A study commissioned by the German Energy Agency Dena[30] found that *"due to increasing transport distances and international power transit, the demand for reactive power in the transmission grid will increase significantly by 2030."*

1.3.4. <u>*Presentation of the options*</u>

Option 0 - BAU

In a business-as-usual scenario, non-frequency ancillary services are mainly provided by large conventional generators. Although those services are currently not remunerated in all Member States, TSOs would need those generators to run even if not profitable. Therefore such generators would request additional revenues. This scenario prevent the access to additional revenue streams for new types of generation assets, mainly being RES E.

Since RES E are displacing conventional generation assets, the supply of these services is becoming scarcer. As a result, generation from RES E would be curtailed at certain times to guarantee the safe operation of the electric network. This would likely slow down the deployment of RES E and affect negatively the achievement of the European wide renewable energy consumption targets by 2020 and 2030 and related climate goals.

Option 0+: Non-regulatory approach.

The Third Package does not address the provision of non-frequency ancillary services in a way that could be used to enforce existing legislation stronger. Voluntary cooperation does not provide the necessary minimum degree of harmonization and legal certainty to allow for efficient cross-border trade. Even where non-frequency anciliary services have to be provided on a local level, the provision of and revenues from these services can

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[29] *"Technical and Economic analysis of the European Electricity System with 60% RES"* (2015) Alain Burtin & Vera Silva, http://www.energypost.eu/wp-content/uploads/2015/06/EDF-study-for-download-on-EP.pdf

[30] *"Dena Ancillary Services Study 2030"* (2014) German Energy Agency, http://www.dena.de/en/projects/energy-systems/dena-ancillary-services-study-2030.html

have a significant impact on the competitiveness of electricity generation, which competes cross-border.

Option 1 - EU rules setting out a framework for a transparent, non-discriminatory, market based framework

This option would imply setting EU wide harmonized rules in EU legislation on requirements of generators for connection to the grid, on specifications and procurements of products to ensure a level-playing field and fair remuneration of these services. This would encounter a number of issues: even though the provision of non-frequency ancillary services is necessary to run a European wide electricity market, due to the local/regional character of these services, optimal solutions may vary across Member States. Additionally, it would require the coordination of both transmission and distribution system operators as a large fraction of RES E is installed at the distribution level. These services are not generally remunerated at lower voltage levels and no clear framework is yet available on how to regulate these services. Finally, there are still significant challenges for market based integration of ancillary services from RES E due to limitations of predictability of energy output.

Option 2 - Guidelines setting out the principles for the adoption of a transparent, non-discriminatory, market based framework.

The aim is to provide a sound basis for the development of a non-discriminatory, transparent and market based access to non-frequency ancillary services by RES E and to allow the gradual phase-in of services based on local/regional needs and best practices. This is a pre-requisite for a cost efficient allocation of resources to provide the necessary supply of non-frequency ancillary services. The measures should be articulated along the following main lines:

- ensure that the regulatory requirements for the provision of these services are rational with respect to the expected needs (both in terms of quantity and location) and non-discriminatory with respect to different assets capable of providing the service.
- bring transparency to the way ancillary services are procured, for instance through market-based tenders or auctions and allow sufficient flexibility in the process to accommodate bids from assets with different technical characteristics;
- promote mechanisms for remuneration by system operators;
- consult stakeholders when establishing new rules to make sure all assets can participate to these services while providing support for safe grid operation.

These measures are also conducive to a higher penetration of RES E in the electricity network and could be further developed in a dedicated network code.

1.3.5. *Comparison of the options*

The BAU scenario would not be effective in designing a level-playing field for a non-discriminatory, transparent and market based access to non-frequency ancillary services and in achieving the objectives of increasingly integrated RES E in a European electricity market. It would also be an obstacle for further increase of RES E in the generation mix with a potential negative impact on the achievement of the 2030 targets. In the current situation, where ancillary services are provided by conventional generators, curtailment of RES E is required at times to assure the availability of generation assets capable of providing ancillary services (so-called "must run"). The decision to keep these resources online is not based on economic assessments, but only on operational considerations for a safe operation of the grid. Such constraint would not exist or not to the same extent if RES E resources would be used to their fullest potential to provide non-frequency ancillary services.

Options 1 and 2 would be more effective in providing a non-discriminatory, transparent and market-based environment for RES E and new technologies to offer and compete for the provision of non-frequency ancillary services. Companies, especially owners of RES E assets would benefit from additional revenue streams from ancillary markets. Extrapolating the European wide market size for non-frequency ancillary services from national markets (typically in the range of tens of millions of euros) puts it roughly in the range of a few billion euros.

In addition, the investment outlook for additional power plants would be better for owners of RES E assets. Taking Ireland as a best practice case, regulators and TSOs are redesigning the ancillary service market in such a way that RES E can participate. It requires introducing new services and allowing these services to be remunerated. This has the additional benefit that the electricity generation share of RES E in such a redesigned market can be higher without compromising the safe operation of the grid and allows system operators to make efficiency gains: the Irish All Island TSOs compared the estimated costs of enhancing the operational capabilities of ancillary services with the benefits of lower market prices coming from a larger share of wind energy generation. They concluded that the benefit outwheighted the costs already at System Non-Synchronous Penetration levels below 50%[31].

Based on the studies and sources mentioned in this and other Sections of this annexe, little uncertainty exists about the benefits of more transparent provision of ancillary services, one where RES E could participate. For certain services, especially those that have a limited geographical scope, it is unclear if and how liquid markets could be established, with regulated cost+ payments being a possible alternative.

The second Option is preferred over the first one, because at this moment there is not enough evidence to support European wide harmonized rules for non-frequency ancillary services. New services are being developed and new market players are emerging. The first option could preclude unknown future developments in this area, whereas the second option allows the gradual phase-in of services based on local/regional needs and best practices.

1.3.6. *Subsidiarity*

Even though non-frequency anciliary services, such as voltage related ancillary services have a local character, it does not prevent action through the market design initiative. The efficient provision of these services is a critical enabler of an integrated European

[31] *"Onshore wind supporting the Irish grid"* (2013) Andrej Gubina, http://www.reservices-project.eu/wp-content/uploads/D5.1-REserviceS-Ireland-case-study-Final.pdf

electricity market and of higher RES E penetration. Also, the assets that provide non-frequency ancillary services are largely the same ones providing frequency-related services: a local problem due to voltage stability could have implications for the provision of frequency-related services and the stability of the grid at a European level as a whole. Finally, the assets providing ancillary services are generally competing in other markets with a larger geographical scope, including the day ahead and intraday electricity markets. Conditions on voltage control thus have an impact on cross-border competition in electricity markets.

1.3.7. *Stakeholders' opinions*

RES E[32] and demand response[33] industry associations and owners of storage[34] assets assert the technical availability to provide non-frequency ancillary services, but expose difficulties accessing the market because of non-transparent rules for contracting, minimum product size and other product specifications, as well as procurement lead times. Younicos, a storage provider, states that *"storage is not defined in regulatory framework on national or EU level, creating uncertainty on market access and creating uncertainty on ownership roles."* Similarly, the Association of European Manufacturers of automotive, industrial and energy storage batteries (EUROBAT), calls for a legislative definition of storage which allows system operators to own and operate battery storage. The association calls for the value of services offered by storage systems, including voltage control, frequency control and ramp control, to be financially recognized. Anciliary services should thus be compensated[35]. The European Wind Energy Association points out that the reactive power requirements at low active power set points imposed on RES E in the frame of the RfG code could potentially have a substantial negative impact on the investment costs of new wind power plants..

Energinet.dk considers increased competition for the supply of ancillary services *"as a part of the continuous development of the energy only market with the objective to create clear price signals and creating socio economic benefits and security of supply on short and long run"*. Geographical requirements for delivery of ancillary services is a challenge in developing these markets as well as the fact that grid components such as *"synchronous compensators and HVDC VSC-convertors have a potential to deliver system supporting services in competition with commercial power plants. This development demands transparency in the procurement process to secure optimal planning, operations and investments"*[36].

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[32] *"Balancing responsibility and costs of wind power plants"* (2015) European Wind Energy Association, http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA-position-paper-balancing-responsibility-and-costs.pdf

[33] *"Mapping Demand Response in Europe today"* (2015) Smart Energy Demand Coalition, http://www.smartenergydemand.eu/wp-content/uploads/2015/09/Mapping-Demand-Response-in-Europe-Today-2015.pdf

[34] *"Technical and regulatory aspects of the provision of ancillary services by battery storage"* (2015) Younicos

35 *"Battery Energy Storage in the EU: barriers, opportunities, services and benefits"* (2016) EUROBAT, http://www.eurobat.org/sites/default/files/eurobat_batteryenergystorage_web.pdf p.30.

[36] "Markets for ancillary and system supporting services in Denmark" (2016) Energinet.dk

Two joint papers by Statkraft and Dong Energy point out that *"in the past, system services have played a marginal role in total economics of power plants. In the future, however, system services will be more important for the individual plant and the value (balance of supply and demand of these services) to the system are likely to be markedly higher"*, and that *"requirements put into tenders are crucial for the outcome"*.[37]

[37] *"Does the wholesale electricity market design need more products, or more control?"* Part 1 (2015) & Part 2 (2016) Dong Energy & Statkraft

2. Detailed measures assessed under Problem Area I, option 1(b) Strengthening short-term markets

2.1. Reserves sizing and procurement

2.1.1. *Summary table*

Objective: define areas wider than national borders for sizing and procurement of balancing reserves				
	Option 0: business as usual	Option 1: national sizing and procurement of balancing reserves on daily basis	Option 2: regional sizing and procurement of balancing reserves	Option 3: European sizing and procurement of balancing reserves
Description	The baseline scenario consists of a smooth implementation of the Balancing Guideline. Existing on-going experiences will remain and be free to develop further, if so decided. However, sizing and procurement of balancing reserves will mainly remain national as foreseen in the Balancing Guideline. Active participation in the Balancing Stakeholder Group could ensure stronger enforcement of the Balancing Guideline.	This option consists in developing a binding regulation that would require TSOs to size their balancing reserves on daily probablistic methodologies. Daily calculation allows procuring lower balancing reserves and, together with daily procurement, enables participation of renewable energy sources and demand response. This option foressees separate procurement of all type of reserves between upward (i.e. increasing power output) and downward (i.e. reducing power output; offering demand reduction) products.	This option involves the setup of a binding regulation requiring TSOs to use regional platforms for the procurement of balancing reserves. Therefore this option foresees the implementation of an optimisation process for the allocation of transmission capacity between energy and balancing markets, which then implies procuring reserves only a day ahead of real time. This option would result in a higher level of coordination between European TSOs, but still relies on the concept of local responsibilities of individual balancing zones and remains compatible with current operational security principles.	This option would have a major impact on the current design of system operation procedures and responsibilities and current operational security principles. A supranational independent system operator ('EU ISO') would be responsible for sizing and procuring balancing reserves, cooperating with national TSOs. This would enable TSOs to reduce the security margin on transmission lines, thus offering more cross-zonal transmission capacity to the market and allowing for additional cross-zonal exchanges and sharing of balancing capacity.
Pros		Pro – optimal national sizing and procurement of balancing reserves	Pro –regional areas for sizing and procurement of balancing reserves	Pro – single European balancing zone
Cons		Con – no cross-border optimisation of balancing reserves	Con – balancing zones still based on national borders but cross-border optimisation possible	Con – extensive standardisation through replacement of national systems, difficult and costly implementation
Most suitable option(s) Option 2. Sizing and procurement of balancing reserves across borders require firm transmission cross-zonal capacity. Such reservation might be limited by the physical topology of the European grid. Therefore, in order to reap the full potential of sharing and exchanging balancing capacity across borders, the regional approach in Option 2 is the preferred option.				

2.1.2. *Description of the baseline*

Balancing refers to the situation after markets have closed (gate closure) in which a TSO acts to ensure that demand is equal to supply. A number of stakeholders are responsible for organising the electricity balancing market:

- Transmission system operators ('TSOs') keep the overall supply and demand in balance in physical terms at any given point in time. This balance guarantees the secure operation of the electricity grid at a constant frequency of 50 Hertz.
- Balance responsible parties ('BRPs') such as producers and suppliers; keep their individual supply and demand in balance in commercial terms. Achieving this requires the development of well-functioning and liquid markets. BRPs need to be able to trade via forward markets and at the day-ahead stage. They also need to be able to fine-tune their position within the same trading day (e.g. when wind forecasts or market positions change).
- Balancing service providers ('BSPs') such as generators, storage or demand facilities, balance-out unforeseen fluctuations on the electricity grid by rapidly increasing or reducing their power output. BSPs receive a capacity payment for being available when markets have closed ('balancing capacity' also referred to as 'balancing reserve') and an energy payment when activated by the TSO in the balancing market ('balancing energy'). Payments for balancing capacity are often socialized via the transmission network tariffs, whereas payments for balancing energy usually shape the price that BRPs who are out of balance have to pay ('imbalance price').

Currently, national balancing markets in Europe have significantly different market designs and are operated according to different principles[38]. To achieve efficiency gains through a genuine European balancing market, it is essential to provide a set of common principles. As one can expect the adoption of the Balancing Guideline in 2017, it is possible to agree on the baseline, which can be built upon in the market design initiative.

The Balancing Guideline covers, in particular:

- Standardisation of balancing products[39] used by TSOs to maintain their system in balance. The starting point is a situation where, in Europe, the number of balancing products is estimated at some hundred. TSOs will have to reduce this number as much as possible to create a harmonised competitive market.
- Merit order activation of balancing energy based on European platforms, i.e. operational within 4 years after the entry into force, where all TSOs will have access while taking into account cross-zonal transmission capacity available or released after intraday gate closure.

[38] ENTSO-E survey on ancillary services, May 2016: https://www.entsoe.eu/Documents/Publications/Market%20Committee%20publications/WGAS%20Survey_04.05.2016_final_publication_v2.pdf?Web=1

[39] The term "product" refers to different balancing services which can be traded, such as the provision of balancing energy with different speeds of delivery.

- Single marginal pricing ('pay-as-cleared') which reflects scarcity for the remuneration of the participants in the balancing market (i.e. the payment that a participant receives for providing balancing energy to be the same payment as the imbalance price). Thus being individually in imbalance but contrary to the imbalance of the system as a whole, thus helping the system as a whole to stay balanced, gets rewarded rather than penalized.
- Harmonisation of the length of the imbalance settlement periods ('ISP' i.e. the time over which it is measured whether BRPs stay in balance, i.e. they did not sell more electricity than they produced). Trading products are generally not shorter than, but can be multiples of ISP. The length of the ISP is thus of relevance for all market timeframes and not just for the balancing market. In cross-border trade, the biggest common ISP has to be used. Thus, the smallest trading product across Europe is currently 60 minutes which corresponds to the length of the longest ISP across Member States. However, where two Member States have shorter ISPs, shorter products can be traded across their border (e.g. 30 minutes between France and Germany). To increase the trade of short products, the Balancing Guideline proposes a shift to harmonized 15 minutes ISPs[40].

The Balancing Guideline also provides the baseline for integrating renewable energy sources and demand response in the balancing market, in particular:

- Balancing energy gate closure time (i.e. the point in time after which there can be no more balancing energy offers from BSPs) as close as possible to physical delivery, and at least after intraday cross-zonal gate closure (thus a maximum of 60 minutes before real time). Shorter gate closure time allows wind or PV generators and demand response aggregators to update their forecast and to offer remaining energy to the electricity balancing market.
- Possibility to offer balancing energy without a balancing capacity contract. The procurement timeframes for balancing capacity have generally long lead times for which wind or PV power producers and demand response aggregators cannot secure firm capacity.
- Shorter procurement timeframes for balancing capacity (close to real time).

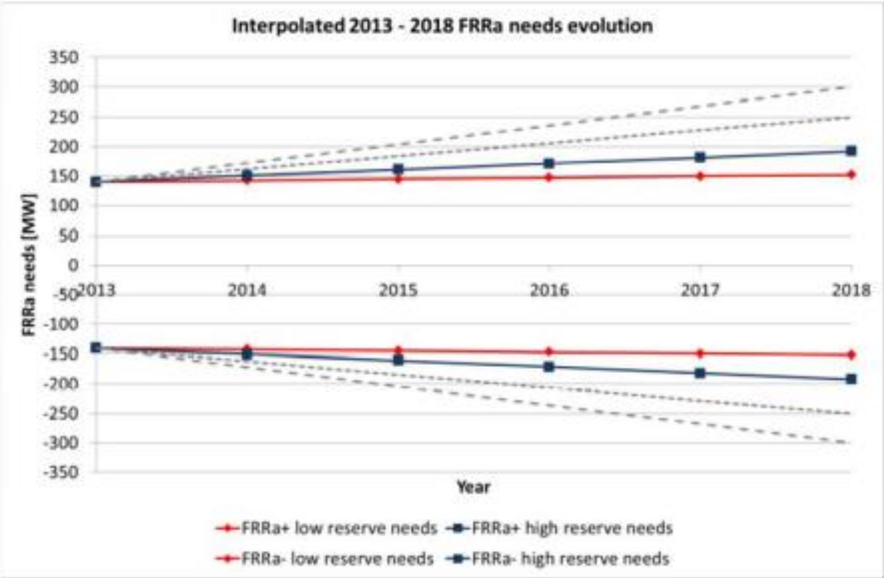
It would be, however, out of the scope of the Balancing Guideline to aim for full harmonization of the currently very diverse balancing markets. The Balancing Guideline includes many exemptions (e.g. central dispatch systems, procurement rules for balancing capacity) and possible derogations (e.g. dual pricing as opposed to single marginal pricing). It is therefore essential that all national balancing markets adhere to a minimal set of common principles.

In addition, balancing reserves are currently mainly sized and procured by TSOs on a national level (except for the Nordic countries and the Iberian Peninsula). This contrasts with the increasing demand for balancing reserves across Europe over the coming

[40] "*Frontier Economics report on the harmonisation of the imbalance settlement period*", April 2016 https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/CBA_ISP/ISP_CBA_Final_report_29-04-2016_v4.1.pdf

decades which is mainly due to large-scale cross-border flows and high volumes of variable RES E generation. Most of the TSOs are sizing their balancing reserves based on potential outages of HVDC interconnectors and forecast errors of renewable energy sources. Despite trends observed in the market (see below figure from ELIA, the Belgian TSO)[41] on the evolution of balancing reserves needs from 2013 to 2018, no significant binding harmonisation is achieved on this subject in the Balancing Guideline.

Graph 1: Interpolated ranges for the volume of reserves needed between 2013 and 2018



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

In their Market Monitoring report 2014[42], ACER points out that in most European markets, the procurement of balancing capacity represents the largest proportion of the overall costs of balancing. The excessive weight of the balancing capacity procurement costs may suggest that the procurement of balancing capacity is not always optimised. ACER emphasis the importance of optimising the procurement costs of balancing capacity, including separate procurement of upward and downward balancing capacity and shorter procurement timeframes.

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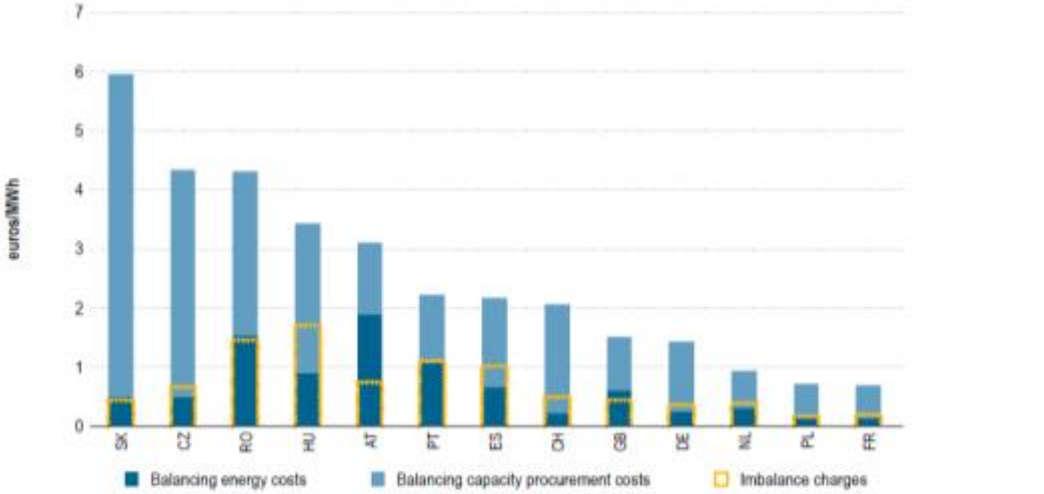
41 Belgian TSO report on the evolution of ancillary services need to balance the Belgian control area towards 2018, May 2013 http://www.elia.be/~/media/files/Elia/Grid-data/Balancing/Reserves-Study-2018.pdf

42 *"Market Monitoring Report 2014"* (2015) ACER, pp. 210.

Graph 2: Overall costs of balancing (capacity and energy) and imbalance charges over national electricity demand in a selection of European markets – 2014 (euros/MWh)



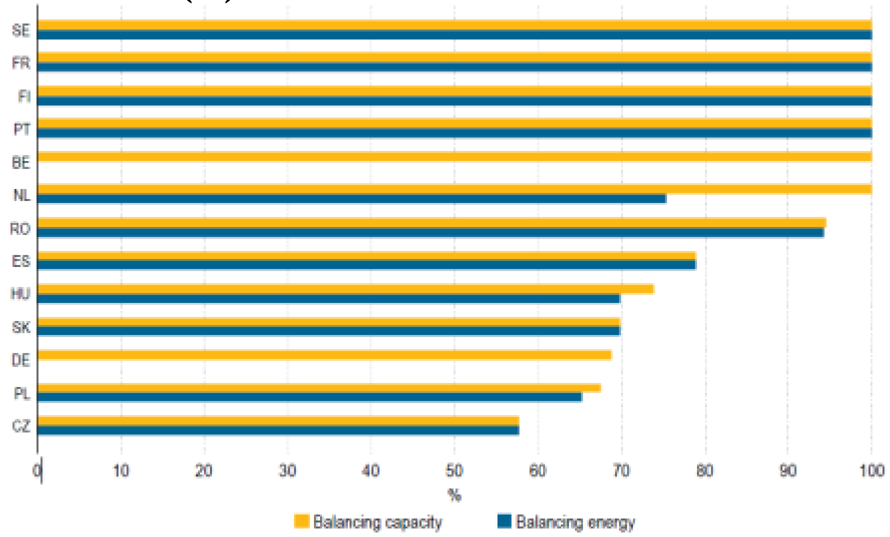
Source: Data provided by NRAs through the ERI, Platts and ACER calculations (2015).

Note: Poland applies central dispatch, and the procurement costs of reserves reported by the TSO are only a share of the overall costs of reserves in the Polish electricity system.

Source: "*Market Monitoring Report 2014*" (2015) ACER, *pp. 209*

Moreover, because only flexible generation assets can provide balancing reserves, balancing markets tend not to be very competitive. Balancing markets are regularly rather concentrated on the supply side as only assets able to adjust production or consumption fast can participate. In their Market Monitoring report 2014, ACER also illustrates the very high level of concentration in the procurement of balancing capacity.

Graph 3: Level of concentration in the provision of balancing services from automatic Frequency Restoration Reserves (capacity and energy) for a selection of Member States – 2014 (%)



Source: Data provided by NRAs through the ERI (2014).

Source: "Market Monitoring Report 2014" (2015) ACER, pp. 207

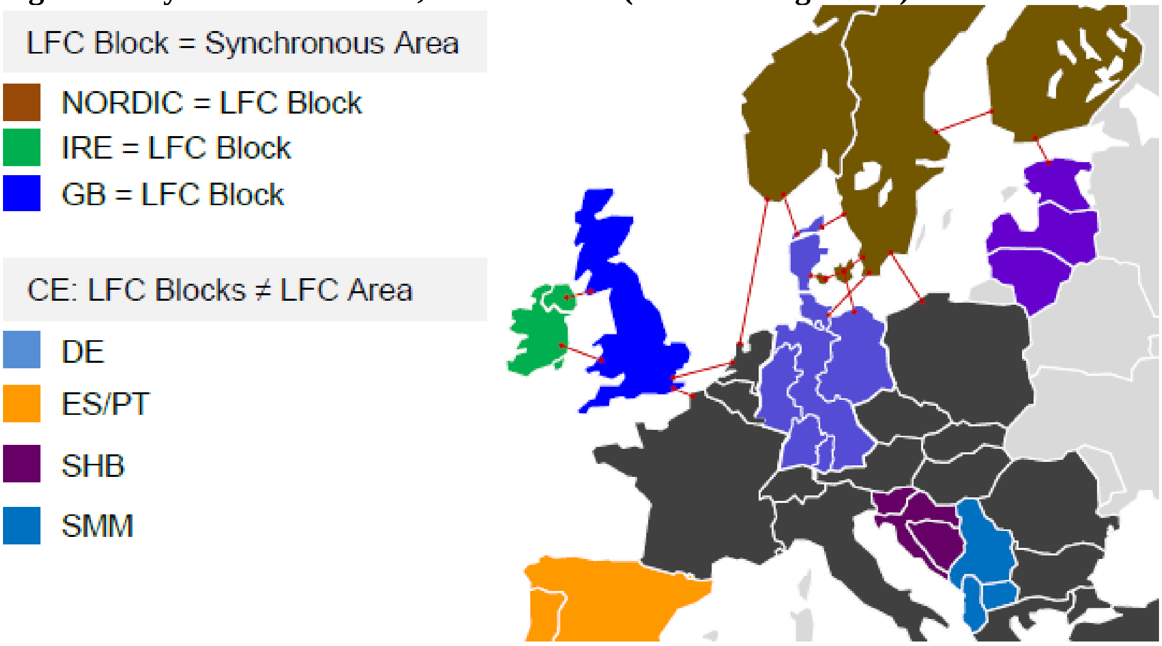
Integrating balancing markets will increase competition and hence will save overall costs. These costs are largely determined by the size of the network area for which the balancing reserves are being procured (also referred to as 'balancing zone' or 'load-frequency control block') and the frequency with which this is done. The size of the reserves that need to be set aside depends on the size of unforeseen events within a given balancing zone. Larger zones across TSO-control areas (effectively across Member States) will result in lower total balancing reserve requirements and reduce significantly the need for back-up generation, as the risks to be covered are smaller than with a simple addition of the risks of two small zones. To this end, a limited number of wider balancing zones should be defined by the needs of the network rather than national borders.

2.1.3. *Deficiencies of the current legislation (see also Section 7.4.2 of the evaluation)*

Recitals and provisions containing reference to transparent, non-discriminatory and market-based procedures for the procurement of balancing capacity are contained in the Electricity Directive. However, there is nothing more specific to the procurement rules. As part of the regional cooperation of TSOs, Article 12.2 of the Electricity Regulation refers to the integration of balancing and reserve power mechanism. However, no further details are being developed concerning the sizing of balancing reserves at regional level.

The Guidelines on System Operation (approved in Comitology on 4^{th} of May 2016) harmonise terms, methodologies and procedures for sizing balancing reserves, but it is expected that balancing zones (or LFC Blocks) will remain unchanged and mainly based on national borders (except for Nordic countries and Spain-Portugal) as illustrated below.

Figure 1: Synchronous Areas, LFC Blocks (or balancing zones) and LFC Areas



Source: ENTSO-E supporting document for the Network Code on Load-Frequency Control and Reserves, 2013, pp. 42

The Balancing Guideline (not yet approved in Comitology) intends to set out rules for the procurement of balancing capacity, the activation of balancing energy and the financial settlement of BRPs. It would also require the development of a harmonised methodology for the reservation of cross-zonal transmission capacity for balancing purposes. However sharing and exchange of balancing capacity would not be mandatory under the Balancing Guideline but encouraged.

2.1.4. *Presentation of the options*

Option 0 - BAU

The baseline scenario consists of a smooth implementation of the Balancing Guideline where sharing and exchange of balancing capacity are not mandatory. In this way, the existing on-going experiences (such as the regional sizing and procurement of balancing reserves in the Nordic countries and the Iberian Peninsula) will remain and be free to develop further and integrate, if so decided by the participating parties. Isolated and likely incompatible projects may be implemented across Europe.

Procurement arrangements such as shorter contracting period close to real time should be enforced in line with the development of a methodology for the reservation of cross-zonal transmission capacity for balancing purposes.

Option 0+: Non-regulatory approach

The Third Package does not address the provision of regional sizing and procurement of balancing reserves in a way that could be used to stronger enforce existing legislation.

Specific parts dealing with transparency, non-discrimination and market based rules can be found in the Article 15 of the Electricity Directive. Others parts dealing with the regional cooperation of TSOs on balancing and the optimal allocation of capacity across timeframes can be found in Article 12.2 and Annex 1.2.6 of the Electricity Regulation.

Voluntary cooperations between TSOs for sharing and exchaning balancing capacity could be further supported thanks to an active participation in the Balancing Stakeholder Group established by ACER and ENTSO-E for an early implementation of the Balancing Guideline. However no mandatory provisions in the Balancing Guideline request TSOs to size and procure reserves at regional level.

Option 1 – National sizing and procurement of balancing reserves on a daily basis

This option consists in developing a binding regulation that would require TSOs to size their balancing reserves on daily probabilistic methodologies (i.e. based on different variables such as RES E generation forecasts, load fluctuations and outage statistics). This method is opposed to a deterministic approach which consists of sizing the balancing reserves on the value of the single largest expected generation incident. Daily calculation allows procuring lower balancing reserves and, together with daily procurement, enables participation of renewable energy sources and demand response.

Shorter procurement timeframes for balancing capacity facilitate the participation of wind generators and demand response aggregators which cannot secure firm capacity over long lead times, or storage operators, which do not have to guarantee specific amounts of energy stored over long periods. This option foresees separate procurement of all types of reserves between upward (i.e. increasing power output; offering demand reduction) and downward (i.e. reducing power output; offering demand increase) products.

Option 2 – Regional sizing and procurement of balancing reserves

This option involves the set up of a European binding regulation requiring TSOs to use regional platforms for the procurement of balancing reserves. Mandatory sharing and exchange of balancing capacity requires firm cross-zonal transmission capacity. Therefore this option foresees the development of an optimisation process for the allocation of transmission capacity between energy and balancing markets, which then implies procuring reserves only a day ahead of real time.

This option thus has the focus on a more integrated approach on the sizing and procurement of balancing reserves themselves. Mandatory regional procurement of balancing reserves would require changing and harmonizing adjacent business and related operational processes. Mandatory regional sizing of balancing reserves might have an impact on system operation procedures and responsibilities, at least procedurally shifting security of supply-related tasks (such as system's state analysis) to a supranational level (possibly to newly-established regional operational centres ('ROCs'), see also Section 2.3).

TSOs would still be responsible for real-time activation of the balancing capacity procured; however they would only have access to the regional platforms for the procurement of balancing capacity which would assume harmonized procurement timeframes and centralised optimisation algorithm requiring firm cross-border transmission capacity to be available. Balancing reserves would be estimated on a daily basis and based on probabilistic methodologies.

Option 3 – European sizing and procurement of balancing reserves

This option would result in a significant evolution of the current design in which European electricity systems are operated. This would have a major impact on the current design of system operation procedures and responsibilities.

This option involves setting up a binding European framework to ensure that all Member States implement a single market design for sizing and procurement of balancing reserves. A supranational independent system operator ('EU ISO') would be responsible for sizing and procurement of balancing reserves, cooperating with national TSOs. This would enable TSOs to reduce the security margin on transmission lines, thus offering more transmission capacity to the market and allowing for additional sharing and exchanges of balancing capacity.

2.1.5. *Comparison of the options*

Economic impacts

All three options can capture some of the potential social welfare opportunities. Option 3 would be the most effective in achieving an optimal sizing and procurement of balancing reserves at European level. However, it might not be feasible as sharing and exchanges of balancing capacity require firm cross-zonal transmission capacity. Such reservation might be limited by the physical topology of the European grid (e.g. geographical distribution of the balancing reserves to maintain operational security[43]). Option 1, which

[43] ENTSO-E supporting document for the Network Code on Load-Frequency Control and Reserves, 2013, pp. 75

foresees daily sizing of balancing reserves at national level and separate procurement of downward and upward balancing capacity, would result in an increased participation of wind power producers and demand response aggregators in the balancing market. While the improvements of national rules regarding sizing and procurement of balancing reserves would allow savings around EUR 1.8 billion, it would not reap the full potential of cross-border exchanges. Daily sizing and procurement of balancing reserves could therefore be optimally performed at regional level. The preferred option is thus Option 2, which brings savings of around EUR 3.4 billion.

Table 1: Economic impacts by option

	BAU	**Option 1**	**Option 2**	**Option 3**
Balancing reserves needs (GW)	53.4	52.1	29.9	17.1
Balancing reserves needs reduction	-	3%	44%	68%
Annual savings (EUR billion)	**-**	**1.8**	**3.4**	**4.5**

Source: METIS

Regulatory impact

The costs of sizing and procuring balancing reserves at regional level are mainly linked to the possibility to add a task to the newly-established regional operational centres ('ROCs') (see also Section 2.3 of the present annexes to the impact assessment). System state analysis would have to be performed on a daily basis and regional level by the ROCs, together with the setting-up of regional plaforms for the procurement of balancing reserves. The option entailing the smallest change (Option 1) involves costs significantly less than the other two options. Option 2 is likely to be more expensive as a result of the additional tasks to ROCs and the setting-up of several new platforms for the exchange or sharing of balancing reserves.

2.1.6. *Subsidiarity*

The subsidiarity principle is fulfilled given that the EU is best placed to provide for a harmonised EU framework for common sizing and procurement of balancing reserves. Most Member States currently take national approaches to size and procure balancing reserves including often not allowing for foreign participation. As common sizing and procurement of balancing reserves requires neighbouring TSOs' and NRAs' full cooperation, individual Member States might not be able to deliver a workable system or only provide suboptimal solutions.

Providing mandatory regional sizing and procurement of balancing reserves would be also in line with the proportionality principle given that it aims at preserving the properties of market coupling and ensuring that the distortions of uncoordinated national balancing mechanisms are corrected and the internal market is able to deliver the benefits to consumers.

2.1.7. *Stakeholders' opinions*

Most respondents from the Market Design consultation agreed with the need to speed up the development of integrated short-term (balancing and intraday) markets. A significant number of stakeholders argue that there is a need for legal measures, in addition to the technical network codes and guidelines under development, to speed up the development of cross-border balancing markets, and provide for clear legal principles on non-discriminatory participation in these markets.

In ENTSO-E's view a parallel harmonization of balancing energy and balancing capacity procedures would lead to unreasonably high effort for TSOs and would introduce additional uncertainty and insecurity for the operation of the electricity system if made mandatory. However ENTSO-E and ACER recognise that common cross-border procurement of reserves is a good target in the long-term.

The March 2016 Electricity Regulatory Forum (the "Florence Forum"), a forum for stakeholders to engage on wholesale market regulatory issues, made the following relevant conclusion:

"The Forum stresses the importance of balancing markets for a well-integrated and functioning EU internal energy market. It encourages the Commission to swiftly bring the draft Balancing Guideline to Member States for discussion, ideally before the summer, with a view to reaching agreeement in autumn this year. It considers, however, that there may still be improvements needed and ask the Commission to consider the provisions of the draft Guideline carefully before presenting a formal proposal.

The Forum supports the view that further steps are needed beyond agreement and implementation of the Balancing Guideline. In particuler, further efforts should be made on coordinated sizing and cross-border sharing of reserve capacity. It invites the Commission to develop proposals as part of the energy market design initiative, if the impact assessment demonstrates a positive cost-benefit, which also ensure the effectiveness of intraday markets."

2.2. Removing distortions for liquid short-term markets

2.2.1. *Summary table*

	Option 0	Option 1	Option 2
Objective: to remove any barriers that exist to liquid short-term markets, specifically in the intraday timeframe, and to ensure distortions are minimised.			
Description	Business as usual Local markets mostly unregulated, allowing for national differences, but affected by the arrangements for cross-border intraday and day-ahead market coupling. Stronger enforcement and volunatry cooperation There is limited legilsation to enforce and voluntary cooperation would not provide certainty to the market.	Fully harmonise all arrangements in local markets.	Selected harmonisation, specifically on issues relating to gate closure times and products.
Pros	Simplest approach, and allows the cross-border arrangements to affect local market arrangements. Likely to see a degree of harmonisation over time.	Would minimise distortions, with very limited opportunity for deviation.	Targets issues that are particularly important for maximising liquidity of short-term markets and allows for participation of demand response and small scale RES.
Cons	Differences in national markets will remain that can act as a barrier.	Extremely complex; even the cross-border arrangements have not yet been decided and need significant work from experts. Additional benefit unclear.	May still be difficult to implement in some Member States with implication on how the system is managed – central dispatch systems could, in particular, be impacted by shorter gate closure time.
Most suitable option(s): Option 2 – Provides a proportionate response targeting those issues of most relevance.			

2.2.2. *Description of the baseline*

Intraday markets usually open several hours before the day of delivery and allow market participants to trade energy products i.e. discrete quantities of energy for a set amount of time - close to real time and as short as five minutes before delivery.

Liquid intraday markets will form a critical part of a European energy market that is able to cost-effectively accommodate an increasing share of variable renewable sources, allow for more demand-side participation, and allow for energy prices to reflect scarcity.

> *"Liquidity is a measure of the ability to buy or sell a product – such as electricity - without causing a major change in its price and without incurring significant transaction costs. An important feature of a liquid market is the presence of a large number of buyers and sellers willing to transact at all times"*[44].

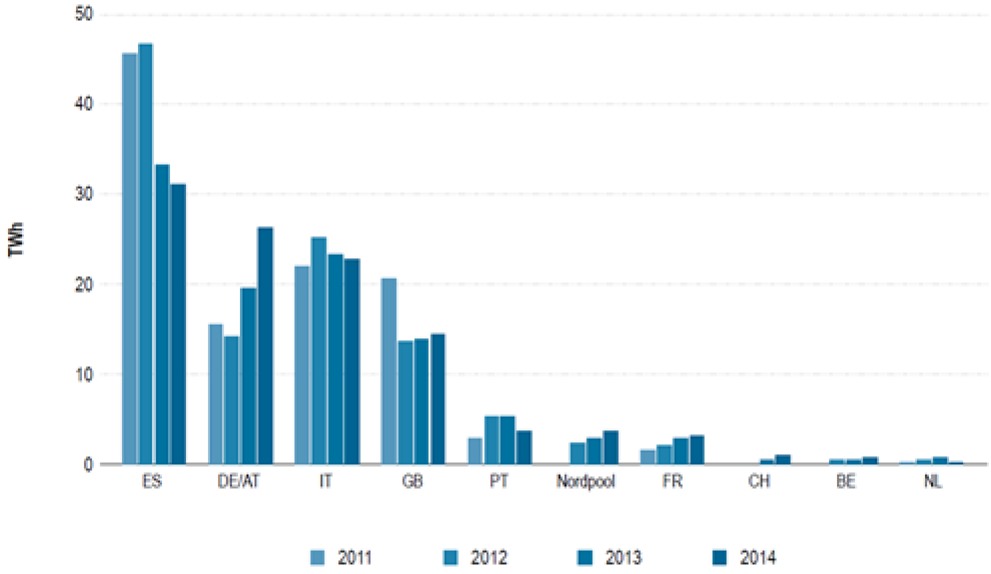
Maximising liquidity in the intraday market will increase competitive pressure, increase confidence in the resulting energy prices, and allow adjustment of positions close to real time, thus reducing the need for TSO actions in the balancing timeframes (although it should be noted that this will not by itself reduce the need for remedial actions by TSOs to address congestion in internal grids).

- The more variable source of renewable generation in the EU energy mix, the more impact of errors in forecasting of weather and demand. Allowing close-to-real-time trading will allow suppliers and producers to take account of the most up-to-date information and, therefore, reduce risk of being out of balance.
- The more trading in this market, the more likely it is to reflect the overall value of staying in balance, thereby increasing confidence in the price. This in turn will affect price formation in the day-ahead market and in forward markets.

Most Member States have organised intraday markets. In their Market Monitoring Report, ACER points out a general trend to an increase in the volumes traded in national intraday markets.

[44] Ofgem, https://www.ofgem.gov.uk/electricity/wholesale-market/liquidity

Figure 1 – ID traded volumes in selection of EU markets – 2011-2014 (TWh).



Source: PXs and the CEER national indicators database (2015), as reported in "Market Monitoring Report 2014" (2015) ACER.

However, there remains significant scope for increasing liquidity. In the same report, ACER analyse 13 markets that make up 95% of the liquidity in intraday markets, using as a liquidity indicator the ratio of energy volumes traded to demand. The following shows that only 5 markets had a ratio above 1%.

ES	IT	PT	DE	GB	SI	BE	SE	LT	FR	CZ	NL	PL
12.1%	7.4%	7.6%	4.6%	4.4%	1.0%	1.0%	1.0%	1.0%	0.7%	0.7%	0.2%	0.1%

The organisation of national intraday markets is largely unregulated in EU law. A degree of harmonisation has developed naturally, partially due to common actors in national markets. However, significant differences still remain. In particular:

- whilst most countries operate a continuous trading approach, some have intra-day auctions;
- gate closure times (i.e. when the market closes) vary from between 5 minutes (BE and NL) to 120 minutes (HU) ahead of real time. In the Iberian market, which operates auctions, the shortest gate closure time is just over two hours, and can extend even further depending on the hour of delivery;
- the granularity of products varies between 60 minute products and 15 minute products;
- the minimum size of bids varies between 0.1MWh to 1MWh;
- the types of orders vary considerably;
- demand response is not consistently allowed to participate;
- whether bidding is at unit-level or portfolio-level;
- whether the organised intraday-markets are exclusive (i.e. preventing bi-lateral trading).

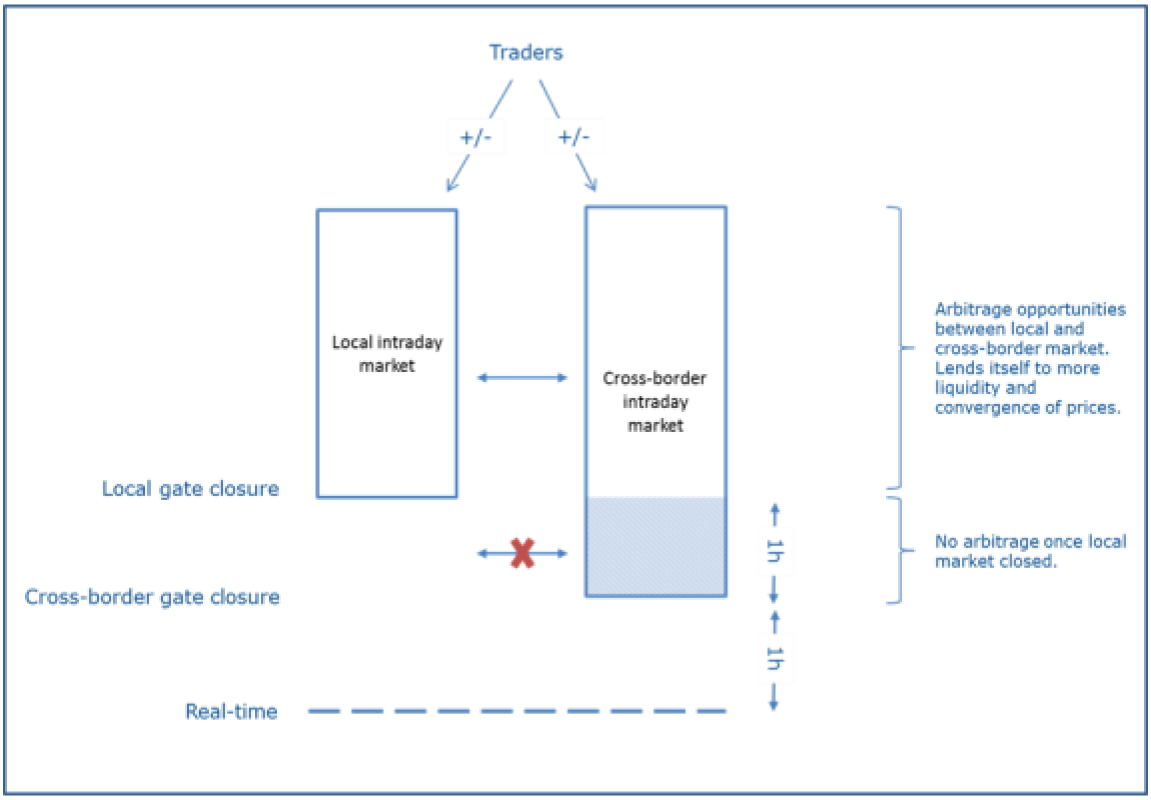
Currently, cross-border trading in the intraday timeframe is not harmonised, is generally on a border-by-border basis and the total traded volumes are low: in 2014 only 4.1% of IC capacity was used intraday, compared to 40% day-ahead.

The CACM guideline[45] envisages a new, EU-wide cross-border market in the intraday timeframe. Local markets will be indirectly impacted by its introduction, essentially because it provides an extra choice for market participants on which platform to trade. There are important interactions, notably because the two markets co-existing in this way has the potential to split liquidity (i.e. split the trading across two markets as opposed to one, thereby reducing the benefits of a highly liquid market). The more differences that exist between local markets and between local markets and the cross-border market, the greater the impact is likely to be as arbitrage opportunities between them will be reduced.

One issue exists in particular – that of gate closure times. The below diagram is an illustration of the potential interactions between local and cross-border markets. While both are open for trading, market participants can chose the best one, most likely driven by price and/or products which match their needs, but potentially also by functionality and ease-of-use of the trading platform. As such there should be a general trend towards convergence of prices in these two markets as they will effectively be in direct competition with each other. The more similarities in the specificities of the markets the more likely this is to be the case. However, if the local market closes before the cross-border market, the arbitrage opportunities are reduced as the market participants cannot freely trade between the two. There is also a risk that local rules will mean that continued cross-border trading will not be possible once the local market has shut, for example because it is on this basis which the suppliers and producers provide 'firm' details on their contracted energy to the TSO. The existence of different products and arrangements, and even different IT systems on which to trade, also bears the risk of splitting liquidity between different markets. However, whilst the longer-term objective should be to have one, common market where all trading takes place and where liquidity is 'pooled', given the starting point it is not necessarily beneficial to deliver this by harmonising all arrangements in the short-term, as it could involve moving to the 'lowest common denominator,' as described further below.

[45] Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management.

Figure 2 – Example co-existence of local and cross-border markets, where local market closes before cross-border.



The design of some national markets may limit the ability for RES E or Demand Response to participate, as they will prefer shorter products as this will help them accommodate more variability in generation and demand. Also, if products do not at least reflect the imbalance settlement period, then market participants will not have the ability to balance themselves sufficiently frequently.

Finally, the closer to real time that market parties are allowed to trade, the more likely it is that their supply and demand will be in balance when it comes to delivering and consuming energy. This is especially relevant in a market sensitive to weather fluctuations where changes can happen after the market has closed and the participants are not able to buy or sell energy to make up for this. It therefore becomes the responsibility of the TSO as part of the balancing market. However, the risk is that, if set too close, TSOs will not have the time they need after being informed of the final market results to manage the system and, in particular, deal with internal bottlenecks.

2.2.3. *Deficiencies of the current legislation*

As detailed above, there is very limited legislation in this area. The most significant piece is the CACM Guideline, but this only indirectly addresses the operation of national markets and, in most cases, will not directly lead to standardised trading within local markets, which thereby potentially creates a barrier to cross-border trade and liquidity.

The Evaluation Report for market design concluded that *"the Third Energy Package does not ensure sufficient incentives for private investments in the new generation capacities and network because of the minor attention in it to effective short-term markets and prices which would reflect actual scarcity."*[46]

2.2.4. <u>*Presentation of the options*</u>

Option 0 – Business as Usual

This option would leave local markets mostly unregulated, allowing for national differences, but influenced by the arrangements for cross-border intraday and day-ahead market coupling. The CACM Guideline requires the definition of a gate closure time on each bidding zone border, which can be a maximum of 60 minutes. This could impact decisions taken at national level, but this is not certain and differences are likely to remain. Further, the definition of the products that can be taken into account in the cross-border system are to be determined under the CACM Guideline which could, again, impact the products which are provided in local markets.

Option 0+ Non-regulatory approach

There is very limited legislation in this area. Stronger enforcement of current rules therefore does not provide scope to achieve a larger degree of harmoninsation of intraday trading arrangements.

Voluntary cooperation has resulted in significant developments in the market and a lot of benefits. However it may not provide for appropriate levels of harmonisation or certainty to the market and legisaltion is needed in this area to address the issues in a consistent way.

Option 1 – Fully harmonise all arrangements in local markets.

This option would see all arrangements harmonised, including gate opening times, gate closing times, products to be offered, whether markets are exclusive, and mandatory continuous trading rather than auctions. Gate closure time would be established as close to real time as possible, to provide maximum opportunity for the market to balance its positions before it became the TSO responsibility. Markets would be exclusive – i.e. no bilateral trading – and power exchanges would be obliged to offer small products, in size and duration – likely a minimum of 0.1MWh in 15 minute blocks. Demand response would be able to participate in all markets.

Given the difference in technical characteristics of different markets (i.e. some have very limited internal congestion so very short gate closure times are technically feasible, whilst others need more time to take remedial actions), this option would likely see some markets becoming larger (with gate closure times closer to real time) and some smaller (with gate closure times having to move further away from real time, depending on the

[46] Section 7.3.2 of the Evaluation

precise time chosen). It would also mean that products would not necessarily reflect the difference in national systems.

Given the technicalities of this option, it would likely be developed through implementing legislation.

Option 2 - Selected harmonisation, with additional flexibility

This option would introduce standardisation of gate closure time and products in a more flexible way, specifically allowing some flexibility in national markets to reflect their differentiated nature. In particular, under this option, legislation would specify:

- that intraday gate closure time in national markets must not be longer than the cross-border intraday gate closure time. This would ensure that national markets are not 'taken out of the picture' before the cross-border markets close, and would, in effect, mean that at a minimum market participants are allowed to trade as close as one hour ahead of real time.
- that power exchanges must offer products that reflect the imbalance settlement period. This will ensure that market participants are able to trade at a frequency which allows them to stay in balance.
- that barriers to demand response participating in intraday markets must be minimised – specifically, minimum bid size should allow for participation and there should be no administrative barriers put in place.

This option would also see more principles added to legislation, with the aim of progressive harmonisation over time on those design features not touched.

2.2.5. *Comparison of the options*

Option 0 (Business as usual) would keep the *status quo* and leave intraday markets to evolve within Member States, with no guarantees they would develop along the same lines, except in some areas that existing legislation touches (for example, on minimum and maximum bid prices). There would likely be an impact as a result of the implementation of market coupling in the intraday time-frame. With significant differences, there is a risk that liquidity is split and benefits of short-term markets to the integration of RES E and demand response muted.

Option 1 – full harmonisation – would likely see significant changes in a number of markets. It would involve selecting a gate closure time and applying that to all national markets. Whilst the precise timing could vary, it would mean that some countries would need to keep their markets open longer, and some would need to close their markets earlier than they currently do (notably in Belgium and the Netherlands, where trades can currently take place up to 5 minutes prior to delivery) – harmonising gate closure times to that of the shortest in Europe would likely be unachievable for many Member States, particularly larger ones where the TSO requires more time between knowing the market results and real time in order to solve internal congestion (the market is blind to congestion within a bidding zone).

This option would also involve harmonising other aspects, as detailed above. Power exchanges can be seen as the conduit for energy trades across borders so harmonising the rules on which trading takes place will minimise differences between national markets and with the common cross-border market. By increasing the arbitrage opportunities across these markets, the risk of splitting liquidity is reduced.

On the surface, this might seem like an appropriate response akin to other single market measures that harmonise standards so that they can be traded within the EU with minimal barriers. However, in reality this is likely to be much more complex. A significant amount of the process is IT-driven, and the arrangements have not yet been put in place – it would therefore be very difficult to determine what the local arrangements should be. Further, there is a lack of evidence that such harmonisation would indeed lead to more cross-border trade – the costs associated with changing IT could be significant with little benefit.

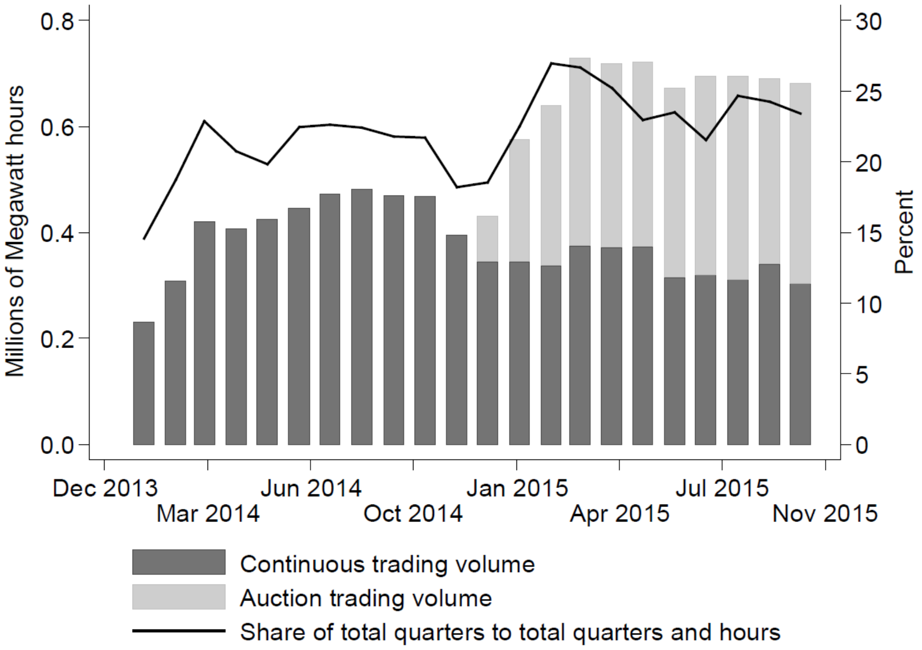
Given that the common cross-border market will likely be more complex (e.g. given the number of variables, Member States, the fact that calculations will need to consider available cross-border capacity) in the immediate future this market, and the IT infrastructure that supports it, may not be able to accommodate the more granular market arrangements that exist in some Member States. As such, moving all national markets to the same design details of that of the cross-border market could entail some having to reduce their granularity, move gate closure time further away from real-time, etc. This would not fit with the objectives of the present proposal, which aims for increased flexibility.

Option 2, however, would provide a much more proportionate response. Rather than specifying a value for the gate closure time in local markets it would specify that it should be no longer than the cross-border gate closure time. It will provide more opportunity for arbitrage between markets. It will also move gate closure times closer to real-time in many markets, which will provide more opportunities for RES E to balance themselves and demand response to participate in the market, without forcing those markets which already apply very short-term trading rules to switch to longer timeframes. With regards to products the markets should be able to accommodate demand-response and small-scale RES E. It will also leave the most technical characteristics to the implementation of the CACM Guideline, which has the advantage of allowing specifics to be discussed in detail with market parties and for more flexibility, i.e. allowing for easy adaptation if and when requirements need to change.

Whilst this option will not eliminate the risk of splitting liquidity, there is in fact some evidence that two markets can co-exist and increase overall traded volumes. In a study looking at the impact of the introduction of an intraday auction for 15 minute products in Germany[47], it was found that, whilst the auction pulled some value away from the continuous intraday market, the total traded volumes increased.

[47] "*Intraday Markets for Power: Discretizing the Continuous Trading"* Karsten Neuhoff, Nolan Ritter, Aymen Salah-Abou-El-Enien and Philippe Vassilopoulos (2016)

Figure 3: Volumes on the 15mn intraday market and the share of quarters in total trading volumes (quarters+hours), EPEX (DE)



Source: Neuhoff et al (2016)

The option will also provide a good starting point for progressively harmonising with the longer-term aim of **one, common intraday market with local specificities minimised to situations where they are justified due to local differences.**

Specific impacts relating to changes in short-term markets are discussed in Section 6.1.3. With regards to intraday, the results of the modelling indicate positive impacts of harmonising intraday arrangements in Europe, specifically allowing for the further reduction of RES E curtailment and lesser use of replacement reserves by 460 GWh and 95 GWh, respectively

2.2.6. *Subsidiarity*

Given that the EU energy system is highly integrated, prices in one country can have a significant effect on prices in another, as can arrangements in local markets. Differences in the operation of local markets can present a barrier to the cross-border trade of energy, and continuing differences between local markets, and between local markets and the single cross-border market, risks splitting liquidty and constraining the benefits of a common cross-border market This will impact on liquidity and the amount of trading which can take place, as well as erode the benefits of competition and a larger market place in which energy can be bought and sold.

EU-level action is, therefore, necessary to ensure that the national markets are comparable, that they enable maximum cross-border trading to happen, and facilitate liquidity as much as possible. .

There is also a critical link with the CACM Guideline, which establishes principles and required further methodologies for the operation of intraday markets in the cross-border context, as well as a link with the upcoming Balancing Guideline. EU-level action is required to ensure that trading in local markets can reap maximum benefits of the cross-border solution under development.

2.2.7. _Stakeholders' opinions_

Most stakeholders agree on the importance of liquid short-term markets, particularly intraday and balancing, to the efficient operation of the internal electricity market. They are, in general, seen as a critical part of ensuring that RES E can be propely intergrated, notably allowing renewable generators to trade closer to real-term, as well as to stimulating investment in sources of flexibility such as demand response. Most call for speedy implementation of common cross-border intraday trading (market coupling) via the XBID project, whilst recognising the progress that has already been made in day-ahead market coupling.

Wind Europe calls upon the EU to "*ensure continuous intraday trading with harmonised gate closure times closer to real time; complementary auctions may be introduced to increase liquidity*". They argue that "*implementing well-functioning intraday markets across borders with gate-closure close to real-time will 1) provide renewable producers with opportunities to adjust their schedule in case of forecasts errors, 2) smooth out the variability induced by renewable in-feed over broader geographical areas*"[48].

In their publication *"Electricity Market Design: fit for the low-carbon transmision"*, Eurelectric state:

"The development of robust cross-border intraday and balancing markets will be crucial to ensure that the system remains balanced as the share of renewables continues to grow. It is therefore necessary to promote a liquid continuous implicit cross-border intraday market with harmonised products in all member states, while capacity pricing shall not drain liquidity nor reduce the speed of market processes. The market shall be enabled to determine the most economic dispatch until a gate closure set as close to real-time as possible (e.g. 15 minutes). TSOs shall only perform the residual balancing of the system."[49]

SolarPower Europe state *"progress is needed in particular with a view to achieving better liquidity and integration of intraday and balancing markets. These short-term markets are crucial as variable renewable energy sources take a more important role in the power mix. Products and services should be re-defined to improve the granularity of these markets and enable the sale of different system services that solar power and other renewables, but also storage and demand participation can provide."* [50]

ENTSO-E make the point that *"Accurate short-term market price formation is needed to reveal the value of flexibility in general and of DSR specifically"*[51] and ACER/CEER that "*it is imperative that everything is done to make sure that price signals reflect scarcity and to create shorter-term markets which will reward those who provide the flexibility services which the system increasingly needs."* Further, they state that *"the intraday and*

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

49 *"Electricity Market Design: fit for the low-carbon transmision"*. Eurelectirc 2016, available at http://www.eurelectric.org/media/272634/electricity_market_design_fit_for_low-carbon_transition-2016-2200-0004-01-e.pdf

50 *"Creating a competitive market beyond subsidies"* July 2015,

51 *Market Design of Demand Side Response"* Policy Paper, November 2015

balancing markets will be increasingly important to valuing flexibility and there needs to be a push to deliver the cross-border intraday (XBID) project and to implement the Network Code on Electricity Balancing as soon as possible."[52]

The March 2016 Electricity Regulatory Forum (the "Florence Forum"), a forum for stakeholders to engage on wholesale market regulatory issues, made the following relevant conclusion:

"The Forum acknowledges that, whilst cross-border day-ahead and intraday markets will see significant harmonisation as part of the implementation of the Capacity Allocation and Congestion Management guideline, there is significant scope for ensuring that national markets are appropriately designed to accommodate increasing proportions of variable generation. In particular, the Forum invites the Commission to identify those aspects of national intraday markets that would benefit from consistency across the EU, for example on within-zone gate closure time and products that should be offered to the market. It also requests for action to increase transparency in the calculation of cross-zonal capacity, with a view to maximising use of existing capacity and avoiding undue limitation and curtailment of cross-border capacity for the purposes of solving internal congestions."

[52] Joint ACER-CEER response to European Commission’s Consultation on a new Energy Market Design, October 2015

2.3. Improving the coordination of Transmission System Operation

2.3.1. *Summary table*

Objective: Stronger coordination of Transmission System Operation at a regional level				
	Option 0	Option 1	Option 2	Option 3
Description	BAU Limit the TSO coordination efforts to the implementation of the new Guideline on Transmission System Operation (voted at the Electricity Cross Border Committee in May 2016 and to be adopted by end-2016) which mandates the creation of Regional Security Coordinators (RSCs) covering the whole Europe to perform five relevant tasks at regional level as a service provider to national TSOs.	Enhance the current set up of existing RSC by creating Regional Operational Centers (ROCs), centralising some additional functions at regional level over relevant geographical areas and delineating competences between ROCs and national TSOs.	Go beyond the establishment of ROCs that coexist with national TSOs and consider the creation of Regional Independent System Operators that can fully take over system operation at regional level. Transmission ownership would remain in the hands of national TSOs.	Create a European-wide Independent System Operator that can take over system operation at EU-wide level. Transmission ownership would remain in the hands of national TSOs.
Pros	Lowest political resistance.	Enlarged scope of functions assuming those tasks where centralization at regional level could bring benefits A limited number (5 max) of well-defined regions, covering the whole EU, based on the grid topology that can play an effective coordination role. One ROC will perform all functions for a given region. Enhanced cooperative decsion-making with a possibility to entrust ROCs with decision making competences on a number of issues.	Improved system and market operation leading to optimal results including optimized infrastructure development, market facilitation and use of existing infrastructure, secure real time operation.	Seamless and efficient system and market operation.
Cons	Suboptimal in the medium and long-term.	Could find political resistance towards regionalisation. If key elements/geography are not clearly enshrined in legislation, it might lead to a suboptimal outcome closer to Option 0.	Politically challenging. While this option would ultimately lead to an enhanced system operation and might not be discarded in the future, it is not considered proportionate at this stage to move directly to this option.	Extremely challenging politically. The implications of such an option would need to be carefully assessed. It is questionable whether, at least at this stage, it would be proportionate to take this step.
Most suitable: Most suitable option(s): Option 1 (Option 2 and Option 3 constitute the long-term vision)				

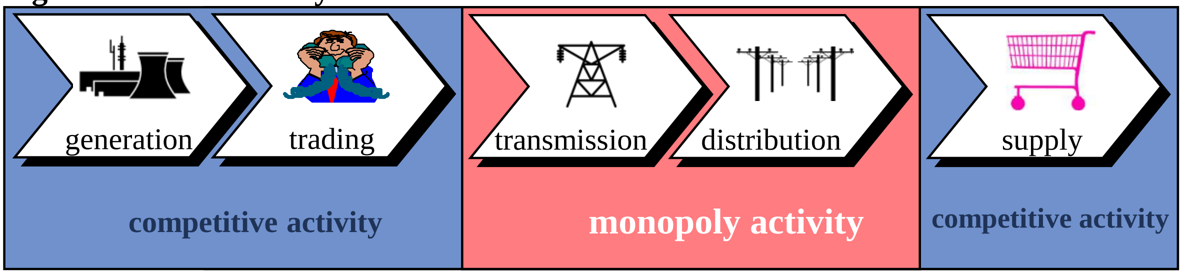
2.3.2. *Detailed description of the baseline*

Operation of the transmission system

Traditionally, prior to the restructuring of the energy sector, most electricity utilities were run by national and very often state-owned monopolies. These were in most cases vertically integrated utilities that owned and operated all the generation and system assets in their allocated territories.

The adoption and implementation of the three energy packages have led to the introduction of competition in the generation and supply of electricity, the introduction of wholesale electricity markets for the trading of electricity as well as to different degrees of unbundling of transmission and distribution activities, which constitute monopoly activities.

Figure 1. The electricity value chain



Source: European Commission

The fact that the activity of electricity transmission system operation is mostly national in scope derives from the past existence of vertically integrated utilities that were active throughout the whole electricity supply value chain. Following the restructuring of the electricity sector, Member States naturally tasked TSOs with the responsibility of ensuring the secure operation of the electricity system at national level.

This approach is currently reflected in the EU legislation. Article 12 of the Electricity Directive establishes that each TSO shall be responsible, *inter alia*, for managing the electricity flows on the system, taking into account exchanges with other interconnected systems. The Commission Implementing Regulation establishing a guideline on electricity transmission system operation ('System Operation Guideline') specifies further this obligation and sets out a requirement on TSOs to ensure that their transmission system remains in the normal state and makes them responsible for managing violations of operational security[53].

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

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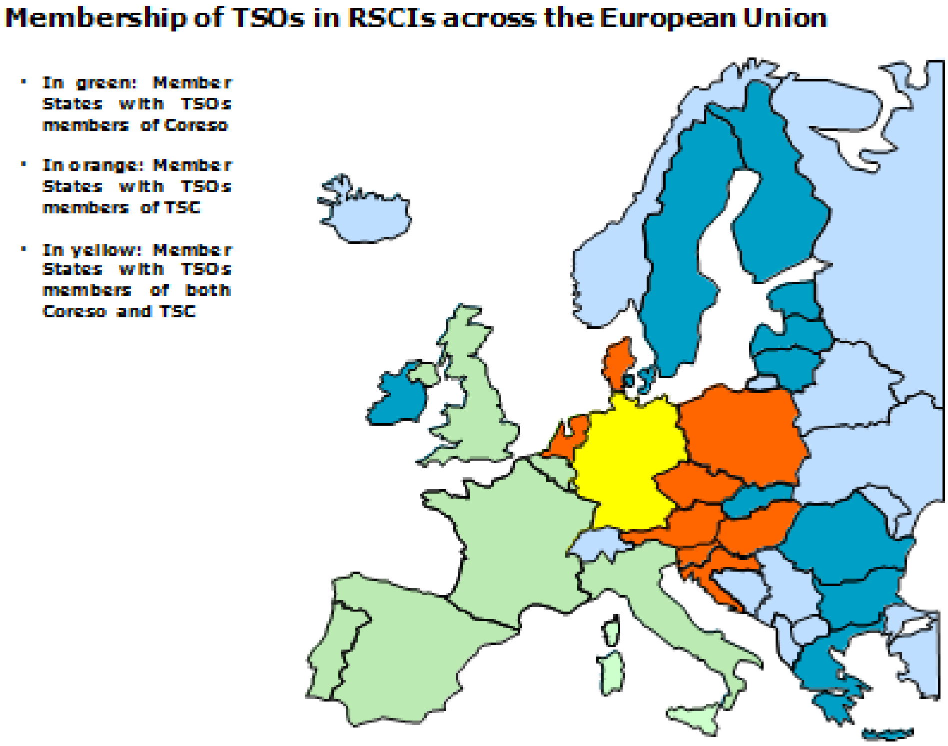
[53] The System Operation Guideline was voted on 4 May 2016 and is due to be adopted after scrutiny by the Council and the European Parliament. https://ec.europa.eu/energy/sites/ener/files/documents/SystemOperationGuideline%20final%28provisional%2904052016.pdf

Driven by the lessons learnt from the serious electrical power disruption in Europe in 2006, European TSOs have pursued enhancing further regional cooperation and coordination. To this end, TSOs voluntarily launched Regional Security Coordination Initiatives (RSCIs), entities covering a greater part of the European interconnected networks aiming at improving TSO cooperation. The main RSCIs in Europe are Coreso and TSC, both launched in 2008, followed by the ongoing development and establishment of additional RSCIs, such as SCC in Belgrade (launched in 2015) and an RSCI to be launched by Nordic TSOs by the end of 2017. Currently, RSCIs monitor the operational security of the transmission system in the region where the TSOs with membership in the RSCIs are established and assist TSOs proactively in ensuring security of supply at a regional level. By performing these functions, RSCIs provide TSOs with detailed forecasts of security analysis and may propose coordinated measures that TSOs may decide or not to implement.

In December 2015, all European TSOs except for SEPS a.s., the Slovakian TSO, signed a multi-lateral agreement to roll out RSCIs in Europe and to have them deliver core services to support the TSOs carry out their functions and responsibilities at national level.

R&D results: Tools for TSOs to deal with an increase in cross-border flows and variability of generation are being developed in European projects like ITESLA and UMBRELLA. They show that coordinated operational planning of power transmission systems is necessary to cope with increased uncertainties and variability of (cross-border) electricity flows. These tools help decrease redispatching costs and the available cross-border capacity and flexibility while ensuring a high level of operational security.

Figure 2 State of play of the voluntary membership of TSOs in RSCIs across the European Union.



Source: European Commission (June 2016)

The voluntary establishment of RSCIs has been widely recognised as a positive step forward for the enhancement of cooperation of transmission system operation and has been recently formalised in EU legislation with the new System Operation Guideline.

Building on the emerging regional initiatives, the System Operation Guideline takes a further step and mandates the cooperation of EU TSOs at regional level through the establishment of maximum six regional security coordinators (RSCs) which will cover the whole EU to perform a number of relevant tasks at regional level as service providers to national TSOs.

The tasks that RSCs will perform pursuant to the System Operation Guideline are: (i) regional operational security coordination; (ii) building of the common grid model; (iii) regional outage coordination; and (iv) regional adequacy assessment. The task of capacity calculation follows from the implementation of the CACM Guideline and is not assigned in the System Operation Guideline. The draft Commission Regulation establishing a network code on Emergency and Restoration intends to extend the tasks of RSCs to include a consistency assessment of the TSOs' system defence plans and restoration plans.

The framework set out in the System Operation Guideline is meant to build on the existing voluntary initiatives of TSOs (Coreso and TSC). It requires each TSO to join a RSC and allows a degree of flexibility to TSOs to organise the coordination of regional system operation. In this regard, the TSOs of the different capacity calculation regions will have the freedom to appoint more than one RSC for that region and to allocate the tasks, as they deem most efficient, between them.

Based on the deadlines for implementation envisaged in the System Operation Guideline, RSCs should be fully operational around mid-2019.

Box 1: Support functions to be carried out by RSCs under the network codes and guidelines

Common grid model: The common grid model provides an EU-wide forecasted view of all major grid assets (generation, consumption, transmission) updated every hour. RSCs will participate in the iterative process starting from the collection of individual grid models prepared and shared by TSOs and aiming at delivering to all RSCs and TSOs, a common grid model adequate for the other functions listed below. This function is required at least for timeframes from year-ahead to intraday (year-ahead, week-ahead, day-ahead, and intraday).

Operational planning security analysis: RSCs will identify risks of operational security in any part of their regional area (mainly triggered by cross-border interdependencies). They will also identify the most efficient remedial actions (i.e., actions implemented by TSOs aimed at maintaining or returning the electricity system to the normal system state) in these areas and recommend them to the concerned TSOs, without being constraint by national borders. This function covers at least the day-ahead and intraday timeframes.

Coordinated capacity calculation: RSCs will calculate the available electricity transfer capacity across borders, using flow-based (FB) or net transfer capacity (NTC) methodologies. These methodologies aim at optimising cross-border capacities while ensuring security of supply. This function is carried out at least on the D-2 (for day-ahead capacity allocation) and D-1/ intraday (for intraday capacity allocation) timeframes.

Short and very short-term adequacy forecasts: RSCs will provide TSOs with consumption, production and grid status forecasts from the day-ahead up to the week-ahead timeframe. In particular, RSCs will perform a regional check/update of short/medium term active power adequacy, in line with agreed ENTSO-E methodologies, for timeframes shorter than seasonal outlooks. This function is carried out week-ahead (until day-ahead only if scarcity is detected or if there are changes in relevant hypotheses compared to week-ahead).

Outage planning coordination: This function consists in creating a single register for all planned outages of grid assets (overhead lines, generators, etc.). RSCs will identify outage incompatibilities between relevant assets whose availability status has cross-border impact and limit the pan-European consequences of necessary outages in grid and electricity production by coordinating planning outages. RSCs will carry out this function in the year-ahead timeframe with updates up to week-ahead (on TSO requests).

Consistency assessment of the TSOs' system defence plans and restoration plans: RSCs will assist TSOs in ensuring the consistency of the system defence plans and restoration plan.

2.3.3. *Deficiencies of the current legislation*

The regional TSO cooperation model resulting from the adoption of electricity network codes and guidelines constitutes a positive development compared to the existing voluntary cooperation. However, as explained below, this step, while being effective in the short-term, is not sufficient in the medium and long-term.

The unprecedented changes concerning the integration of the European electricity markets and the European agenda for a strong decarbonisation of the energy sector, resulting in increasingly higher shares of decentralized and often intermittent renewable energy sources, have made the operation of the national electricity systems much more interrelated than in the past.

The recently voted System Operation Guideline has not entered into force and been implemented yet. Nonetheless, as highlighted in pp 32-33 of the Evaluation, the challenges the EU power system will be facing in the medium to long-term are pan-European and cannot be addressed and optimally managed by individual TSOs, rendering the current legal framework concerning system operation not adapted to the reality of the dynamic and intermittent nature of the future electricity system and putting into question whether the mandated cooperation of TSOs via RSCs is fit for purpose in the post 2020 context.

First, the functions envisaged for RSCs in the System Operation and in the CACM Guideline will not suffice in the medium to long-term as there is an increasing need for electricity systems to be operated on a regional basis. Furthermore, there is room to enlarge the scope of functions that would increase the efficiency of the overall system, if performed at regional level.

Second, the geographical scope of RSCs set out in the System Operation Guideline could not be efficient in the post 2020 context. RSCIs have grown organically with political considerations in mind, rather than following criteria solely based on the technical operation of the grid. The degree of flexibility envisaged in the System Operation Guideline will allow TSOs to maintain that *status quo*, undermining the goal of having a regional entity that oversees system and market operation in the region. **Figure 2** representing the current membership of TSOs in RSCIs across the Union reflects this situation (e.g., membership of TenneT NL, the TSO of the Netherlands, in TSC as opposed to Coreso). The coordination with other regional groupings of TSOs deriving from the implementation of other network codes and guidelines is also an issue. For example, given the degree to which the grid is meshed in the CWE and CEE regions, it is virtually impossible to draw permanent lines dividing the regions and still respect the electrical interdependencies. Hence, the presence of two RSCIs (Coreso and TSC) for this region does not seem the optimal solution to play an effective coordination role.

Third, the implementation of the System Operation Guideline will entail that RSCs will play an increasingly important support role for TSOs. However, the full decision-making responsibility will remain with TSOs who will have to do the grid planning while taking into consideration also new options to grid extensions (such as energy storage). RSCs will not have executive powers and their activities will be limited to providing planning services to individual TSOs, who can accept or reject those services and who will retail full control of and accountability for the planning and operation of their individual networks. For example, when deciding about the commercial cross-border capacities in a given region which are already calculated at regional level, the decision taken by RSCs are non-binding meaning that they can be considered as an input that can be changed by TSOs based on national interest (e.g. in case of scarcity of supply in one country the TSO might be tempted to reduce their export capacities but this might not be the best decision from a regional system security perspective) or due to constraints in the national legal framework. In this regard, the rejection of a recommendation by a TSO would suffice to put in question the overall set of recommendations issued by a RSC. For example, if in a recommendation for an optimal set of remedial actions a given TSO did not agree, this would imply the whole recalculation of remedial actions for the region since such measures are usually interdependent. There is additional evidence pointing out to this problem. The ACER market monitoring report 2015 (to be published in 2016) remarks that there are strong indications that during the capacity calculation process TSOs resort to unequally treating internal and cross-zonal flows on their networks.

To conclude, while the enhanced regional TSO cooperation resulting from the adoption of electricity network codes and guidelines constitutes a positive step forward, it is important to note that it will not allow realising the full potential of these regional entities in the medium to long-term. If the benefits of market integration are to be fully realised, TSOs will have to cooperate even more closely at regional level. This will require adjusting the way in which the operation of the electricity system will be managed under the System Operation Guideline.

2.3.4. *Presentation of the options*

Option 0 - BAU

Option 0 would be to stop the coordination efforts at this stage and limit it to the progress achieved with the implementation of the System Operation Guideline.

The upcoming RSCs will have the following features:

i. Functions. Five main functions[54] will be performed by the upcoming RSCs as service providers to national TSOs under the network codes and guidelines (see **Box 1** above for a more detailed explanation of each of these functions).

    a. Coordinated Security Analysis (including Remedial Actions-related analysis)
    b. Common Grid Model Delivery
    c. Outage Planning Coordination
    d. Short and Very Short Term Resource Adequacy Forecasts
    e. Coordinated Capacity Calculation

    The addition of new functions would mainly depend on the voluntary initiative of TSOs, which in some instances could lead to inefficient outcomes given that they would not always have the "regional" perspective in mind but rather their own interest, particularly given the flexibility at the time of defining the geographical scope.

    Geographic scope. While RSCs will give full coverage across the EU, the size and composition of the regions where they will be established may not always be defined having the technical operation of the grid in mind. Business and political criteria could also play a role. In particular, TSOs in a region would continue having flexibility to decide which RSC provides a given service (including new ones developed voluntarily) to that region. This would allow a given region to get services from different RSCs. While this has been accepted as a valid compromise in the short-term, it undermines the goal of having a regional entity with enhanced overview over system and market operation in the region.

[54] Six functions with the adoption of the Emergency and Restoration network code *('Consistency assessment of TSOs' system defence plans and restoration plans').*

ii. Decision-making responsibilities. The upcoming RSCs will not have any decision-making powers but a purely advisory role. The responsibility for system operation will remain with TSOs at national level. The fact that RSCs issue recommendations means that ultimately an individual TSO may be constrained by the national framework and reject the implementation of such recommendation, against the interest of all the other TSOs of the region. Hence, the set up of the RSC being able to provide an added value at regional level would be compromised. For example, as described above, if in a recommendation for an optimal set of remedial actions a given TSO did not agree, this would imply the whole recalculation of remedial actions for the region since these measures are usually interdependent.

iii. Institutional layout/governance. The interaction between the RSCs, NRAs, TSOs, ACER and ENTSO-E would remain as set out in the System Operation Guideline. Essentially, TSOs and NRAs would continue to be responsible for the direct implementation and oversight of RSCs at national level. ACER and ENTSO-E would remain responsible for ensuring the cooperation of NRAs and TSOs at EU level, respectively.

Option 0+: Non-regulatory approach

Stronger enforcement would not suffice to address the needs of the electricity system regarding stronger TSO cooperation at regional level.. As in option 0, any progress beyond the framework in the System Operation Guideline and the application of other network codes would depend on the voluntary initiatives of TSOs. However, the voluntary initiatives would be limited due to the constraints resulting from differing legislation at national level. Hence, stronger enforcement or a voluntary approach is not a possible option.

Option 1: Enhance the current set up of existing RSCs by creating ROCs, centralising some additional functions over relevant geographical areas and optimising competences between ROCs and national TSOs

Option 1 would aim at enhancing the current set up of existing RSCs by creating ROCs. ROCs are not meant to substitute TSOs but to complement their role at regional level. This option would set out a number of basic elements in legislation but allow flexibility to TSOs to work out the details on how the ROCs will function and perform their tasks. ROCs will present the the following features:

i. Functions. Enlarged scope of functions, assuming new tasks where centralization at regional level could bring benefits. These functions would not cover real time operation which would be left solely in the hands of national TSOs. In addition to the functions emanating from existing network codes and guidelines (see **Box 1**), these functions would be:

   a. Solidarity in crisis situations: Management of generation shortages; Supporting the coordination and optimisation of regional restoration
   b. Sizing and procurement of balancing reserves
   c. Transparency: Post-operation and post-disturbances analysis and reporting; Optimisation of TSO-TSO compensation mechanisms
   d. Risk-preparedness plans (if delegated by ENTSO-E)

e. Training and certification (if delegated by ENTSO-E)

ii. Geographic scope. A limited number of well-defined regions, covering the whole EU. TSOs establishing the ROCs will need to decide the scope of these regions based on technical criteria (e.g. grid topology) to ensure that they can play an effective coordination role. In contrast to what is currently in the System Operation Guideline, each ROC would perform all functions for a given region. Larger regions could include, if necessary, back-up centres and/or sub regional desks when for example some functions would require specific knowledge of smaller portions of the grid.

iii. Cooperative decision-making. ROCs would have an enhanced advisory role for all functions. In order to respect to the maximum possible extent the regional recommendations, TSOs should transparently explain when and why they reject the recommendation of the ROC. Given that a role limited to issuing recommendations may lead to sub-optimal results as regards the performance of some of the functions[55], decision-making powers could be entrusted to ROCs for a number of relevant issues (i.e., remedial actions, capacity calculation) either directly by a Regulation or subsquentely by mutual agreement of the NRAs or Member States overseeing a certain ROC. By optimising decision-making responsibilities between ROCs and national TSOs the seamless system operation between the ROCs and the TSOs would be ensured.

iv. Institutional layout/governance. Enhanced cooperation between TSOs would be accompanied by an increased level of cooperation between regulators and governments as well as by an increased oversight from ACER and ENTSO-E.

[55] This sub-optimal situation would derive from the fact that the rejection by a single TSO of the recommendation issued by the ROC would put in question the overall set of recommendations.

Box 2: Additional functions performed by ROCs under Option 1

- **Solidarity in crisis situations:**
  - *Management of generation shortages*. ROCs would optimise the generation park in a region while **attempting** to increase transmission capacity to the Member State which suffers generation shortage. The aim of this function is to avoid load cuts (energy non served situations) in a country while other countries still optimise the market and/or enjoy high generation margins.
  - *Supporting the coordination and optimisation of regional restoration*. ROCs would recommend the regional necessities during restoration (e.g., resynchronisation sequence of large islands in case of the split of a synchronous area).
- **Sizing and procurement of balancing reserves:**
  - *Regional calculation of daily balancing reserves*. ROCs would carry out regional sizing of daily balancing reserves (disregarding political borders and considering only technical limitations related to geographical dispersion of reserves) on the basis of common probabilistic methodologies (i.e. balancing reserve needs based on different variables such as RES generation forecast, load fluctuations and outage statistics).
  - *Regional procurement of balancing reserves*. ROCs would create regional platforms for the procurement of balancing reserves, complementing the regional sizing of balancing reserves.
- **Transparency:**
  - *Post operation and post disturbances analyses and reporting*. ROCs would carry out centralised post-operations analyses and reporting, going beyond the existing ENTSO-E Incidents Classification Scale (ICS).
  - *Optimisation of TSO-TSO compensation mechanisms*. ROCs would administer common money flows among TSOs, such as Inter-TSO Compensation (ITC), congestion rent sharing, re-dispatching cost sharing, cross-border cost allocation (CBCA). Furthermore, ROCs should propose improvements to the schemes based on technical criteria and aiming for the optimal overall incentives.
- **Risk-preparedness plans.** If delegated by ENTSO-E, the ROCs' function would be to identify the relevant risk scenarios in its region that the risk preparedness plans should cover. Based on ROCs' proposals, Member States would develop the plans. ROCs could organise crisis simulations (stress tests) together with Member States and other relevant stakeholders. During such crisis simulations the plans would be tested to check if they are suited to address the identified cross-border or regional crisis scenarios.
- **Medium term adequacy assessments:** if delegated by ENTSO-E, ROCs would complement the ENTSO-E seasonal outlooks with adequacy assessments carried out in a regional context where possible crisis scenarios (e.g. prolonged cold spell), including simultaneous crisis, should be identified and simulated.
- **Training and certification.** The network code on staff training and certification as foreseen in the ACER framework guideline on system operation is still pending. ROCs could cover functions related to trainings between TSOs as well as centralise of some trainings in issues related to cross-border system operation. Further, this function should allow regional training on simulators (IT system based on a relevant representation of the system, including networks, generation and load).

Option 2: Creation of Regional Independent System Operators

Option 2 would be to go beyond the establishment of ROCs that coexist with national TSOs and consider the creation of Regional Independent System Operators (RISOs) that can fully take over system operation at regional level.

RISOs would have the following features:

i. Functions. RISOs would have an enlarged scope of functions compared to ROCs. In addition to the functions under Option 1, RISOs would also be responsible for real time operation of the electricity system (e.g., operation of real time balancing markets) and for infrastructure planning. Infrastructure related functions could include for example the identification of the transmission capacity needs: proposing priorities for network investments based on the long-term resource adequacy assessment, the situation in the interconnected system and identified structural congestions, while considering an interconnected system without political borders.

ii. Geographic scope. The scope of RISOs would be the same as for ROCs.

iii. Decision-making responsibilities. All system operation functions would be performed by the RISOs, which would have decision-making powers. Existing TSOs would remain as transmission owners and solely operate physically the transmission assets and provide technical support to RISOs (e.g., collection and sharing of data).

iv. Institutional layout/Governance. Additional changes in the institutional framework would be required to enable the RISO approach. For example, it would be necessary to amend the powers and competences of TSOs, of regulatory authorities and of ACER in order to ensure the appropriate oversight of these entities. It would also be necessary to consider aspects such as the financing of RISOs or the applicability of unbundling rules.

Option 3: creation of a European-wide Independent System Operator

Option 3 would imply the creation of a European-wide Independent System Operation (EU ISO) that would take over system operation at EU-wide level.

This entity would have the following features:

i. Functions. The functions would be the same as those proposed under Option 2 for RISOs.

ii. Geographic scope. The EU ISO would be responsible for system operation at EU-wide level.

iii. Decision-making responsibilities: The EU ISO would perform all system operation functions and hence would have decision-making powers. TSOs would solely operate physically the transmission assets and provide technical support to RISOs (e.g., collection and sharing of data).

iv. Institutional layout/Governance: significant changes would be required in the institutional framework to enable the creation of an EU ISO and an effective oversight of its acitivities. It would be necessary to amend the powers and competences of TSOs, of regulatory authorities and of ACER. It would also be necessary to consider aspects such as its financing, monitoring of its performance, etc.

2.3.5. *Comparison of the options*

The following Section provides a comparison of the options described above based on the four main elements identified: (i) functions; (ii) geographical scope; (iii) decision-making competences; and (iv) institutional layout/ governance. Given that only a few studies have been carried out on this field, the assessment of the options will be mainly qualitative, based on the feedback received from stakeholders and on the content of the studies published to date, and providing figures where they exist.

(i) Functions

It is not possible to provide a complete quantification of the costs and benefits of each of the Options as regards the set of functions to be performed at regional or EU level given that few studies have assessed these costs and benefits. However, the insights from several previous studies cover the potential benefits of a supranational approach to system operation.

Table 1 Functions that would be covered under each of the options

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

Source: DG ENER

[56] It could include decision-making powers.
[57] The CACM Guideline provides for regional capacity calculators. However, following the commitments of ENTSO-E, this role could be already assumed for RSCs.
[58] It could include decision-making powers.

Table 2 Qualitative estimate of the economic impact of the Options:

	Option 0: RSC approach	**Option 1**: ROC approach	**Option 2:** RISO approach	**Option 3:** EU ISO approach
Economic Impact				
Enhancing security of supply by minimising the risk of blackouts[59] [60]	0/+	+	++	++
Lowering costs through increased efficiency in system operation[61] [62] [63]	0/+	++	+++	+++
Maximising transmission capacity offered to the market[64]	0/+	++	+++	+++

[59] The financial and social impact of wide area security breaches is enormous: as estimated by ENTSO-E, the economic impact of wide area security breaches could be really important; the cost of a 20 GW load disconnection during a large brownout is estimated to 800 million euros per hour (i. e. 40 euros / kWh). Blackouts have an even higher impact. This provides quantified insight into the importance of optimised emergency and restoration efforts with a central coordination of locally required efforts.

[60] ENTSO-E (2014), "*Policy Paper on Future TSO Coordination for Europe*", Retrieved from: https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/141119_ENTSO-E_Policy_Paper_Future_TSO_Coordination_for_Europe.pdf

[61] The management of generation shortages should increase the regional social welfare as a result of a decrease of financial losses that would otherwise result from disconnection of load. It would also increase solidarity and promote trust in the internal energy market.

[62] Also, some of the benefits will derive from the optimisation of training and certification. TSOs will gain more practical experiences using same tools, practicing common scenarios and sharing best practices. This should lead to faster system restoration and more efficient tackling of regional-wide system events.

[63] A regional approach to adequacy assessment enhances the use of cross-border connections at critical moments, resulting in an overall less required generating capacity in Europe. The enhancement is expected to increase with increasing variable renewable energy in the system. The IEA mentions a benefit of 1.4 euros/MWh based on the study of Booz & co. An example for regional adequacy assessment is provided by the Pentalateral Energy Forum.

[64] A supranational approach (moving local responsibilities to ROCs) to capacity calculation can bring significant welfare benefits due to more efficient use of infrastructure and the consequent benefits coming from the improved arbitrage between price zones. The CACM Guideline Impact assessment estimates the welfare gains of a supranational approach to flow-based capacity calculation to be in the region of 200-600 million euros per year. These benefits would only partially materialise (20% of welfare gains would not be realised) on a voluntary basis, leaving significant parts of the capacities used in a suboptimal manner.

Reducing the need of remedial actions by coordinating and activating in a coordinated way redispatching[65] [66]	0/+	++	+++	+++
Minimising the costs of balancing provision by taking a more coordinated approach towards the sizing of balancing reserves[67] [68] [69]	0/+	++	+++	+++
Optimisation of infrastructure planning[70]	0	0	++	+++

65 Significant benefits are expected by the fact that enhanced TSO cooperation minimises the need for redispatching, especially costly emergency actions. To illustrate, Kunz et al. quantified the benefits of coordinating congestion management in Germany: in case each TSO is responsible to relief overflows within its own zone with its own resources, which reflects the current situation in Germany closest, redispatch costs of 138.2 million euros per year accrue. Coordinating the use of transmission capacities renders costs of 56.4 million euros per year. As a benchmark, one single unrestricted TSO across all zones would have to bear redispatch expenditures of 8.7 million euros per year. Kunz et al. also quantified the benefits of coordinating congestion management cross-border (for the region comprising Germany, Poland, Czech Republic, Austria, Slovakia): without coordination, total costs of congestion management amount to 350 million euros per year, they decrease to 70 million euros per year for optimised congestion management (including remedial actions and flow-based cross-border capacity allocation).

66 Kunz et al., *"Coordinating Cross-Country Congestion Management"*, DIW Berlin , 2016 and Kunz et al., *"Benefits of Coordinating Congestion Management in Germany"*, DIW Berlin, 2013

67 As regards the regional sizing and procurement of balancing reserves, the added value of this function is gain in social welfare due to decreased size of needed balancing reserves and gains in techno-economic optimisation of the procurement of the needed balancing reserves. Shared balancing has cost advantages residing from netting of imbalances between balancing areas and from shared procurement of balancing resources or reserves. This can be based on exchanging surpluses or based on a shared or common merit order for all balancing resources. Mott Macdonald mentions potential overall benefits from allowing cross-border trading of balancing energy and the exchanging and sharing of balancing reserve services of the order of 3 billion euros per year and reduced (up to 40% less) requirements for reserve capacity. This is for a European electricity supply system with roughly 45% renewable energy.

68 Mott MacDonald (2013), "*Impact Assessment on European Electricity Balancing Market*" Retrieved from: https://ec.europa.eu/energy/sites/ener/files/documents/20130610_eu_balancing_master.pdf

69 According to the study carried out by Artelys on Electricity balancing: market integration & regional procurement, regional sizing and procurement of reserves by ROCs could lead to benefits of 2.9 billion Euros (compared to 1.8 billion euros benefits from national sizing and procurement). An EU-wide sizing and procurement of balancing reserves would lead to benefits of 3.8 billion Euros.

70 The added value as regards the identification of the transmission capacity needs at regional level is the provision of neutral, regional view of investments needs. The industry represented by Eurelectric claims that "*Network investment planning and the coordination of TSOs' network investment decisions by the RISOs are the next natural steps.*" As regards the technical and economic assessment of cross-border cost allocation (CBCA) cases, benefits are expected from higher efficiency and quicker processes for important transmission infrastructure projects.

Enhancing transparency[71]	0	0/+	+	+
Costs of implementation72	0/-	-	---	----
Other impacts				
Administrative impacts/ governance	0/-	-	--	---

Source: DG ENER.The assumptions in this table are based on the studies existing in this field as well as on the feedback received from stakeholders in their response to the public consultation and from estimations concerning the resources of RSCs and ENTSO-E.

In sum, as illustrated in Table 2, the set of functions in **Option 0** will entail limited costs and benefits, since many of these functions are already carried out by RSCIs in their supporting role to TSOs. The implementation of the System Operation Guideline and establishment of ROCs will not involve significant changes to the *status quo*. The set of additional functions under **Option 1** will entail efficiency gains and increase social welfare that will derive from providing additional functions to ROCs to be optimised at regional level (as opposed to national level)[73]. In addition, it will entail costs related to the shift of these functions from national to regional level (e.g., development of processes and tools at regional level) and will have an impact on the institutional structures (i.e., need to adapt the institutional framework to ensure the proper monitoring of implementation of the functions). **Option 2** will present additional gains and costs compared to Option 1. The benefits will result from the more integrated operation of the system at regional level as well as from the additional set of functions to be performed by RISOs, which will comprise real-time operation of the electricity system. The costs will derive from the need to develop new methodologies, processes and tools to ensure the performance of these additional functions and the need to adapt the current oversight of

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71 As regards the optimisation of TSO-TSO compensation mechanisms, the added value is increased transparency and step-by-step optimisation of the schemes, resulting in more cost-efficient operation of the system. This is supported by Eurelectric which states that *"Regarding coordination of network investment decisions, this would require the development of mechanisms for inter-TSO money flows. Development of inter-TSO money flows will also allow efficient coordinated redispatching, as requested by the CACM Guideline. This is considered to be a key element for enabling efficient intraday capacity (re-)calculation"*. See Eurelectric, "*Develop a regional approach to system operation*", June 2016. As regards, post operation and post disturbances analyses and reporting, the added value is increased transparency, better regional understanding and improvement process, as well as and potential efficiency gains.

72 The costs of establishing ROCs, RISOs or an EU ISO are estimated to range between 9.9 and 35.6 million EUR per entity. See "*Electricity Balancing*" Artelys (2016). The study does not provide a break out of the costs between Options 1, 2 and 3 but assumes that the costs will vary depending on the functions and responsibilities attributed to these entities.

73 For instance, the management of generation shortages based on seasonal outlooks should increase the regional social welfare as a result of a decrease of financial losses that would otherwise result from disconnection of load.

the performance of these functions. **Option 3** is the option that will entail most economic gains (deriving from the efficiencies of performance of the functions at EU level) and also most implementation costs.

(ii) ***Geographic scope***

In the current context of the rolling out of RSCs (**Option 0**), there will be certain flexibility for TSOs to decide which coordinator provides a given service to a region. This could allow a given region to get services from different providers. While this is an acceptable compromise in the short and medium term, it partly undermines the goal of having a regional entity with enhanced overview over system operation and market operation in the region. In addition, although there will be full European coverage by the RSCs (with a maximum number of 6), the size and composition of the regions is not always defined having the technical operation of the grid in mind. Business and political criteria play also a role in it.

Option 1 would allow ROCs to play an effective coordination role leading to enhanced system security and market efficiency – given that the ROCs would be able to optimise the operations over larger regions[74]. In contrast with Option 0, the regions would be defined according to market and system operation criteria (e.g. grid topology). Having a limited number of ROCs will also bring in savings in developing system operation tools. However, there would be costs related to the need to adapt further the geographical scope from RSCs to ROCs but this could be mitigated through a carefully planned implementation. In Option 1, ROCs would have the possibility to include back-up centres that ensure that one centre can take over from the other if a problem arises and/or include sub-regional desks for looking at issues where a more detailed assessment is needed. This could for example be the case if a ROC is created for the Continental Europe synchronous area (or at least for Central Western Europe and Central Eastern Europe) as a natural evolution of the existing Coreso and TSC coordinators – in this case, it could be natural to have a set up with two locations within a ROC (e.g. Munich and Brussels, if current coordinadors were to keep existing locations).

The benefits and shortcomings of **Option 2** would be similar to those of Option 1 as the geographical scope of both options would be the same.

Option 3 would entail that the EU ISO is responsible for performing all the functions at EU level. This approach would lead to efficiency gains, as it would no longer be necessary to ensure the coordination and cooperation between entities at regional level and all the functions could be performed seamlessly. However, it is questionable whether from a technical point of view, at this stage, a single entity would be capable of carrying out all these functions at EU level even if it envisages setting up sub-regional desks for the more detailed assessment of regions.

(iii) ***Decision-making competences***

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[74] This would also pave the way for a further long term evolution towards Regional Independent System Operators.

In **Option 0**, RSCs have a purely advisory role i.e. the recommendations that they issue can be overriden by TSOs[75]. This would be the option less politically sensitive. However, this can potentially lead to inefficient outcomes. For example, when deciding about the commercial cross-border capacities in a given region which are already calculated at regional level, the decision taken by RSCs in the form of recommendations are non-binding. These decisions can be considered as an input that can be rejected by TSOs based on national interest (e.g. in case of scarcity of supply in one country the TSO might be tempted to reduce their export capacities but this might not be the best decision from a regional system security perspective) or due to constraints in their national framework (e.g., in the case of cross-border remedial actions, a TSO may be obliged to reject the recommendations issued by the ROC given that the national framework requires a different order of implementation of remedial actions).

In **Option 1** ROCs would have an enhanced advisory role for all functions. Under this option, ROCs could be entrusted with certain decision-making competences (as opposed to a pure service provision role) to avoid the possibility of regional optimisation being lost due to national constraints. This approach is likely to lead to more efficient outcomes since there would be a margin for overcoming obstacles deriving from the national framework (e.g. remedial actions, capacity calculation). In the case of the example above, when deciding about the commercial cross-border capacities in a given region which are already calculated at regional level, the decisions taken by ROCs could be final and binding. Whilst this option is likely to bring more efficient outcomes, it is also likely to be more politically controversial, especially with TSOs and Member States. However, other stakeholders have expressed support for this option[76]. This could be done either directly enshrining the functions in legislation or subsequently by mutual agreement of the NRAs overseeing a certain ROC.

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75 Indeed, coordination between TSOs through RSCs could be successful if the national frameworks were harmonised. However, since national frameworks may differ significantly, voluntary coordination is not likely to be optimal in the medium term.

76 Eurelectric has recently pointed out that *"A step-wise regional integration of system operation and of planning tasks relevant to cross-border trade therefore needs to happen. Such a process should build upon the ongoing establishment of RSCs, which are executing a certain number of system operation tasks on behalf of the national TSOs and could be a step towards gradually allocating the responsibility for those tasks to regional entities"*. Eurelectric, *"Develop a regional approach to system operation"*, June 2016. Also, in response to the Commission Public Consultation on a new energy market design, Acciona emphasised that *"system operation should be coordinated at the same level as markets are, to efficiently manage electricity systems as an integrated whole. Therefore, a regional responsibility for system security should gradually replace national responsibilities"*. Also in its response to the Public Consultation, Engie submitted that *"current national responsibility for system operation indeed hampers cross-border cooperation and is not mimicking the progress made on side of market integration: different capacity calculation in the flow based approaches are leading to lower capacity"* and that it *"favours closer cooperation of TSOs and RSCs taking over new functions progressively (eventually replacing national TSOs in those functions). Stepwise approach is needed."* In its response to the Public Consultation, Business Europe has stated that *"establishing regional system operators, based on a costs-benefits analysis, could be a first step towards more operational coordination of TSOs in the future"*.

In **Option 2** with RISOs that can fully take over system operation at regional level, all functions carried out by RISOs would be binding since they would fully replace the functions performed at national level. Entrusting decision making powers to RISOs would be justified based on the fact that system operation decisions might span well beyond the area of a single TSO and affect the whole system. This would be the basis for a regional system operation[77]. However, this option would be extremely sensitive politically and would likely be rejected by many Member States.

Option 3 would require entrusting the performance of the functions and associated decision-making powers to a single entity, the EU ISO, who would take binding decisions. This option would set the basis for a truly European operation of the electricity system. While there would be additional efficiency gains compared to those resulting from Option 2 (e.g., it would no longer be necessary to ensure the coordination of operations of a number of entities at regional level), it is unclear whether this option is technically feasible at this stage. Option 3 would also be politically unacceptable.

(iv) Institutional layout/Governance

Option 0 would not require significant institutional changes, as the interaction between RSCs, NRAs, TSOs, ACER and ENTSO-E would remain as set out in the System Operation Guideline. **Option 1** would require increasing the level of cooperation between NRAs and governments, as well as additional competences for ACER and ENTSO-E, to ensure the oversight of ROCs. **Options 2 and 3** would each require substantial changes to the institutional framework in order to encompass the switch of decision-making powers for system operation from a national to a regional or EU-wide level. The costs and speed of implementation would also increase for each of the options, being Option 3 the most costly and most timely.

(v) Conclusion of evaluation

The Table below provides a qualitative comparison of the Options in terms of their effectiveness, efficiency and coherence of responding to specific criteria.

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[77] In this regard, Eurelectric has highlighted that *"A truly regional system operation can however only be based on a regional decision-making structure and a single operational framework. Establishing regional integrated system operators performing system operation and planning tasks in all regions should therefore be the end goal to allow for more operational coordination of TSOs"*. Eurelectric, "*Develop a regional approach to system operation*", June 2016

Table 1: (The assumptions in this table are based on the feedback received from stakeholders in their response to the public consultation and from additional submissions from ACER)**.**

Criteria	Option 0: BAU	Option 1: ROC approach	Option 2: RISO approach	Option 3; EU ISO approach
Quality	0/+ Progress remains limited due to zones not based on technical operation of the grid	+ More efficient as optimisation over zones based on technical operation of the grid	++ Very efficient because of enhanced system operation at regional level	+++ Most efficient because of seamless system operation at EU level
Speed of implementation	+ Can build upon established structures (RSCIs)	0 Can partially build upon established structures; change in geographical scope and functions	-- Can partially build upon established structures but it will require a substancial centralization at regional level; change in geographical scope of functions; it would require a substantial amount of time for implementation.	--- Cannot build on established structures. Substantial change in geographical scope of functions. It would require a substantial amount of time for implementation
Use of established institutional processes	++ Can build upon established structures (no decision-making responsibility)	- Requires building up new structures/ processes (possibly some decision-making responsibility)	-- Requires building up new structures/ processes (decision-making responsibility for all regional relevant functions)	--- Requires building additional structures and processes that are adapted for the operation of this entity at EU level (decision-making responsibilities for all functions at EU level)
Secure operation of the network	0/+ Mandated cooperation; slightly reduced risk of blackout	+ Enhanced cooperation via ROCs; reduced risk of blackout	++ Integration via RISOs; significantly reduced risk of blackout	+++ Seamless operation at EU level; significantly reduced risk of blackout
Efficient organisational structure	- Sub-optimal organisational structure; a given region can get services from different providers	++ Efficient organisational structure can be created; all services for a region carried out by one company	+++ Efficient organisational structure can be created; all services for a region carried out by one company	+++ Efficient organisational structure can be created; all services at EU level carried out by a single company
Political sensitivity	0 Politically most acceptable as it represents the convergence achieved during discussions with Member States and stakeholders for the System	- Politically sensitive due to shift in decision-making responsibility for relevant functions	-- Extremely politically sensitive due to shift in decision-making responsibility	--- Politically unacceptable at this stage

	Operation Guideline			

In summary:

While **Option 0** will allow achieving some progress in terms of regional coordination which might be sufficient in the short to medium term, it risks falling short and being suboptimal in the post 2020 context with the subsequent negative consequences in terms of system security and market efficiency[78]. It would also affect the effectiveness of many of the other proposals of the market design initiative and be a missed opportunity to propose legislation on the field that can shape the EU power system in the future.

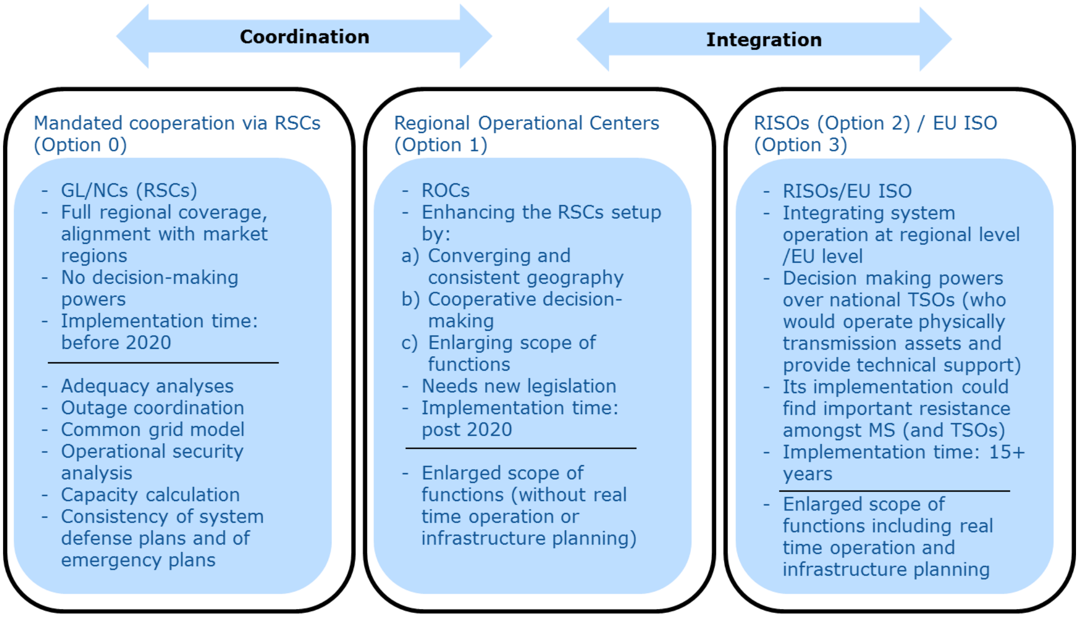
Option 1 is the preferred option to respond to the post 2020 challenges in system operation. Execution of the additional functions as outlined in Option 1 will lead to the ROCs approach, featuring benefits in efficiency and security, but also leading to increased needs for resources at regional level (data systems, experienced staff). Allowing ROCs to be entrusted with certain decision-making responsibilities (as opposed to a pure service provision role) will avoid the possibility of regional optimisation being lost due to constraints resulting from differences in the national frameworks. This option enhances the effectiveness of many other proposals of the market design initiative.

Option 2 and **Option 3** would constitute the most preferable options from the point of view of seamless system operation, efficiency and economic gains. While they should not be discarded as a direction that should be followed in the future, none of these options are considered proportionate at this stage. Moreover, the feasibility of Option 3 is questionable. Option 2 is supported by some stakeholders as a long-term goal[79].

[78] Eurelectric shares this view and has recently stated that "*Current TSOs coordination initiatives such as RSCs are steps in the right direction. The harmonisation and integration requirements developed in the System Operation Guideline are nevertheless not ambitious enough. Indeed, these approaches remain mostly national with the aim to protect the autonomy of individual system operators. Most importantly, those initiatives do not fully equip system operators to cope with the challenges of a low-carbon power power system"*. Eurelectric, *"Develop a regional approach to system operation"*, June 2016

[79] For example, Eurelectric declares that *"A truly regional system operation can however only be based on a regional decision-making structure and a single operational framework. Establishing regional integrated system operators performing system operation and planning tasks in all regions should therefore be the end goal to allow for more operational coordination of TSOs"*. Moreover, it states that *"The transistion towards a truly integrated and decarbonised elecricity market will be more efficient if the electricity system is optimised on a regionla and ultimately a European basis (e.g. TSOs should operate the system as "one"). This will require a high degree of cooperation between system operators and the harmonisation of system operation rules. […] Establishing regional integrated system operators performing system operation and planning tasks in all regions should therefore be the end goal to allow for more operational coordination of TSOs"*. Eurelectric, "*Develop a regional approach to system operation"*, June 2016. In addition, in response to the Commission public consultation on a new energy market design, Fortum submitted that *"the goal should be that the market, in practice, sees only one TSO. It could be done by [an] European TSO or by current TSOs improving their cooperation"*.

Figure 3 below describes a stepwise approach for the implementation of the future ROCs



Source: Commission.

2.3.6. *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 divering opinions as regards the delineation of responsibilities between regional centres and national TSOs and that further consideration was needed[80].

The creation of Regional Operational Centres will be likely seen with concern by TSOs and a large number of Member States which seem to consider that the currently foreseen cooperation via Regional Security Coordinators is fit for purpose. In particular, Member States are likely to oppose any step oriented to entrust regional structures with decision making powers under the assumption that security of supply is a national responsibility. Regarding the regions, Member States might prefer geographical dimensions based on governance rather than what would be optimal from a technical point of view.

80 See Florence Forum conclusions of March 2016: https://ec.europa.eu/energy/sites/ener/files/documents/Conclusions%20-%20Florence%20Forum%20-%20Final.pdf

3. DETAILED MEASURES ASSESSED UNDER PROBLEM AREA I, OPTION 1(C); PULLING DEMAND RESPONSE AND DISTRIBUTED RESOURCES INTO THE MARKET

3.1. Unlocking demand side response

3.1.1. *Summary table*

Objective: Unlock the full potential of demand response			
Option O: BAU	Option 1: Give consumers access to technologies that allow them to participate in price based demand response schemes	Option 2: as Option 1 but also fully enable incentive based demand response	Option 3: mandatory smart meter roll out and full EU framework for incentive based demand response
Stronger enforcement of existing legislation that requires Member States to roll out smart meters if a cost-benefit analysis is positive and to ensure that demand side resources can participate alongside supply in retail and wholesale markets	Give each consumer the right to request the installation of, or the upgrade to, a smart meter with all 10 recommended functionalities. Give the right to every consumer to request a dynamic electricity pricing contract.	In addition to measures described under Option 1, grant consumers access to electricity markets through their supplier or through third parties (e.g. independent aggregators) to trade their flexibility. This requires the definition of EU wide principles concerning demand response and flexibility services.	Mandatory roll out of smart meters with full functionalities to 80% of consumers by 2025 Fully harmonised rules on demand response including rules on penalties and compensation payments.
No new legislative intervention.	This option will give every consumer the right and the means (fit-for-purpose smart meter and dynamic pricing contract) to fully engage in price based DR if (s)he wishes to do so.	This option will allow price and incentive based DR as well as flexibility services to further develop across the EU. Common principles for incentive based DR will also facilitate the opening of balancing markets for cross-border trade.	This guarantees that 80% of consumers across the EU have access to fully functional smart meters by 2025 and hence can fully participate in price based DR and that market barriers for incentive based DR are removed in all Member States.
Roll out of smart meters will remain limited to those Member States that have a positive cost/benefit analysis. In many Member States market barriers for demand response may not be fully removed and DR will not deliver to its potential.	Roll out of smart meters on a per customer basis will not allow reaping in full system-wide benefits, or benefits of economies of scale (reduced roll out costs) Incentive based demand response will not develop across Europe.	As for Option 1, access to smart meters and hence to price based DR will remain limited. Member States will continue to have freedom to design detailed market rules that may hinder the full development of demand response.	It ignores the fact that in 11 Member States the overall costs of a large-scale roll out exceed the benefits and hence that in those Member States a full roll-out is not economically viable under current conditions. Fully harmonised rules on demand response cannot take into account national differences in how e.g. balancing markets are organised and may lead to suboptimal solutions.
Most suitable option(s): Option 2. Only the second option is suited to untap the potential of demand response and hence reduce overall system costs while respecting subsidiarity principles. The third option is likely to deliver the full potential of demand response but may do so at a too high cost at least in those Member States where the roll out of smart meters is not yet economically viable. Options zero and one are not likely to have a relevant impact on the development of demand response and reduction of electricity system cost.			

3.1.2. *Description of the baseline*

For the purpose of this exercise a clear distinction has to be made between technological prerequisites and market arrangements for demand response as those aspects are regulated separately. As such chapter 3.2.1 will focus on the baseline for smart metering and 3.2.2 on dynamic prices and market regulation.

3.1.2.1. Smart Metering

Current Legislation on Smart Metering

Smart metering is a key element in the development of a modern, consumer-centric retail energy system which encompasses active involvement of consumers. In recognition hereof, provisions were included in the Gas Directive and in the Electricity Directive fostering the smart metering roll-out and targeting the active participation of consumers in the energy supply market. These provisions were then complemented with provisions under the Energy Performance in Buildings Directive, and the Energy Efficiency Directive.

The Electricity and Gas Directives[81] require Member States to ensure the implementation of intelligent metering systems that shall assist the active participation of consumers in the energy supply market, and encourage decentralised generation[82], and promote energy efficiency. Article 3 (11) of the Electricity Directive and Article 3(8) of the Gas Directive explicitly state that *"in order to promote energy efficiency, Member States or, where a Member State has so provided, the regulatory authority shall strongly recommend that electricity (or natural gas) undertakings optimise the use of electricity (or gas), for example by providing energy management services, developing innovative pricing formulas, or introducing intelligent metering systems or smart grids, where appropriate."*

This implementation may be conditional, according to Annex I.2 of both the electricity and gas Directive, on a positive economic assessment of the long-term cost and benefits to be completed by 3 September 2012. For electricity, the roll-out can be limited to 80% by 2020 of those positively assessed cases as potentially indicated in a cost-benefit analysis ('CBA'). Furthermore, Member States, or any competent authority they designate, are obliged according to the Electricity and Gas Directive (Annex I.2) to "*ensure the interoperability of those metering systems to be implemented within their territories"* and to "*have due regard to the use of appropriate standards and best practice and the importance of the development of the internal market"* in electricity or natural gas, respectively.

The recast of the Energy Performance of Building Directive ('EPBD'), adopted in May 2010, obliges (Art 8(2)) Member States to "*encourage the introduction of intelligent metering systems whenever a building is constructed or undergoes major renovation,*

81 Annex I.2 of the Electricity Directive and of the Gas Directive.

82 Specifically for electricity and linked to smart grid deployment - Electricity Directive, recital (27)

whilst ensuring that this encouragement is in line with point 2 of Annex I to [the Electricity Directive]".

To assist with the preparations for the roll-out, and based on lessons learned and good practices identified through experiences accumulated in Member States, the Commission adopted the Recommendation on preparations for the roll-out of smart metering systems[83]. It aimed at guiding Member States in their choices, drawing particular attention to: (i) key functionalities for fit-for-purpose and pro-consumer arrangements[84]; (ii) data protection and security issues; and (iii), a methodology for a CBA that takes account of all costs and benefits, to the market and the individual consumer, of the roll-out. Following this Recommendation, complementary smart metering provisions were adopted as part of the Energy Efficiency Directive[85].

Smart Metering Deployment in Member States

According to data from the Commission Report *"Benchmarking smart metering deployment in the EU-27"*, as also recently updated[86], to date 19 Member States have committed to rolling out close to 200 million smart meters for <u>electricity</u> by 2020 at a total potential investment of EUR 35 billion.

- 17 Member States - Sweden, Italy, Finland, Malta, Spain, Austria, Poland, UK-GB, Estonia, Romania, Greece, France, Netherlands, Denmark, Luxembourg, Ireland, and lately Latvia – are targeting a nation-wide roll-out to at least 80% of customers by 2020 (with 13 of them going much beyond the target of the Electricity Directive).
- 2 Member States – Germany, Slovakia - are moving to deployment in a selected segment of consumers (to max. 23% by 2020).
- The rest 9 Member States have either decided against at least under current conditions, or have not made a firm commitment yet for a mass-scale or even a selective roll-out.

By 2020, it is projected that almost 72% of European consumers will have a smart meter for electricity[87]. Smart meters for electricity are already being rolled out across the EU. As of 2013, nearly all consumers in Sweden, Finland and Italy, were equipped with smart meters.

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83 *Commission Recommendation on preparations for the roll-out of smart metering systems (2012)* http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32012H0148

84 When it comes to functionalities for electricity smart metering, particularly important for residential consumers are: a readings' update rate of 15 minutes and a standardised interface to transfer and visualise individual consumption data in combination with information on market conditions and service or price options.

85 Energy Efficiency Directive. Art 9(2), 12(2b)

86 *"Status report based on a survey regarding Interoperability, Standards and Functionalities applied in the large scale roll-out of smart metering in EU Member States"* (2015) Smart Grids Task Force Expert Group 1; https://ec.europa.eu/energy/sites/ener/files/documents/EG1_Final%20Report_SM%20Interop%20Standards%20Function.pdf

87 Report from the Commission *"Benchmarking smart metering deployment in the EU-27 with a focus on electricity"* (2014) http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2014%3A356%3AFIN

Despite the progress noted, these implementation plans are falling short of the legislation's intentions. For various legal and technical reasons, the current advancement is rather slow – particularly in view of the fast approaching 2020 target in the case of electricity – and the progress gap to delivery may be further widened by recurring delays in national programmes[88]. In addition, there is a risk that the systems being rolled-out do not bring all the desired benefits to consumers and the market as a whole as they do not include the necessary functionalities to do so. Furthermore, they might not support in all cases standardised interfaces[89] – at home or station level – for the delivery of these functionalities, nor be complemented with additional specifications for improving interoperability on these interfaces and the smooth exchange of information and inter-working between the metering infrastructure and devices or other network platforms in the energy market.

In all cases, the successful roll-out is controlled to a large extent by Member States who are ultimately responsible for the deployment and respective market arrangements[90], and may or may not decide to follow the guidelines tabled by the Commission regarding functionalities and implementation measures for data privacy and security (see Energy Efficiency Directive (Art 9(2b)) and Commission Recommendations "on the preparations for the roll-out of smart metering systems", and "on the data protection impact assessment template for smart grids and smart metering systems" [91]).

3.1.2.2. Market arrangements for demand response

Legislative Background

Mechanisms to remove the barriers to demand flexibility are set out in the Electricity Directive. The Energy Efficiency Directive ('EED') builds on those provisions and elaborates further, promoting its access to and participation in the market and the removal of existing barriers.

The Electricity Directive refers to demand response measures as a means to pursue a wide range of system benefits. The Directive clearly identifies demand response as an alternative to generation to be considered on an equal footing, e.g. when Member States are launching tendering procedures for new capacity in situations where the resource adequacy is insufficient to ensure security of supply (e.g. Art. 8 Electricity Directive). Demand response, alongside energy efficiency, is viewed as one of the measures to combat climate change and ensure security of supply. Demand response is recognised as a means to provide ancillary services to the system in the provisions related to TSO tasks (Art. 12(d) Electricity Directive), and demand side management/energy efficiency

88 See the Smart Metering Annex of Market Design Evaluation.

89 *"Status report based on a survey regarding Interoperability, Standards and Functionalities applied in the large scale roll-out of smart metering in EU Member States"* (2015) Smart Grids Task Force Expert Group 1.

90 Commission Staff Working Document *"Cost-benefit analyses & state of play of smart metering deployment in the EU-27"* (2014), sections 2.4 and 2.7 http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52014SC0189

91 "*Commission Recommendation on the Data Protection Impact Assessment Template for Smart Grid and Smart Metering Systems"* (2014) http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2014.300.01.0063.01.ENG

measures must be considered as an investment alternative in the context of distribution network development by DSOs planning for new grid capacity (Art. 25(7) Electricity Directive).

Effective price signals are important to encourage efficient use of energy and demand response. In this context, recital 45 of the EED indicates that Member States should ensure that national energy regulatory authorities are able to ensure that network tariffs and regulations support dynamic pricing for demand response measures by final customers. Under Art. 15(1) EED, Member States must ensure that network regulation and tariffs meet criteria listed in Annex XI of the EED, which *inter alia* refer to different possibilities for network and retail tariffs to support dynamic pricing for demand response and incentivise consumers. According to Article 15(4) EED, Member States must ensure the removal of those incentives in transmission and distribution tariffs that might hamper participation of demand response in balancing markets and ancillary services procurement. Most relevant in the context of this impact assessment is however, Article 15(8) EED. In summary, Member States must comply with the following obligations:

- Ensure that national energy regulatory authorities encourage the participation of demand side resources, including demand response, alongside supply in wholesale and retail markets;
- Ensure – subject to technical constraints inherent in managing networks - that TSOs and DSOs treat demand response providers, including demand aggregators in a non-discriminatory way and on the basis of their technical capabilities;
- Promote - subject to technical constraints inherent in managing networks - access to and participation of demand response in balancing, reserve and other system services markets, requiring that the technical or contractual modalities to promote participation of demand response in balancing, reserve and other system services markets - including the participation of aggregators - be defined;
- Ensure the removal of those incentives in transmission and distribution tariffs that might hamper participation of demand response in balancing markets and ancillary services procurement[92].

Situation in Member States with regards to demand response

The EU demand response market is still in its early development phase. This early development has proceeded very differently across Member States that have chosen different approaches to make use of demand side flexibility and to implement demand response. In fact, while Article 15.8 EED formulates principles for the market access of demand service providers and demand side products it has left substantial freedom for Member States to implement these.

While a full transposition check of Art 15.8 EED has not yet been carried out it can already be seen that different national provisions have led to a fragmented European market on demand response with different rules and market opportunities for

[92] See guidance note on Energy Efficiency Directive Art 15 which also covered Industrial Emissions Directive elements http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:52013SC0450

(independent) demand response service providers, different market arrangements between service providers and balancing responsible parties (including compensation payments) and different rules for trading flexibility in the balancing, wholesale and capacity markets.

Explicit (or incentive based) demand response

For explicit demand response, full customer participation in the electricity markets is a prerequisite as addressed in the relevant provisions of the EED. However, because of its complexity only very large industrial consumers can directly engage in the electricity markets while commercial and residential consumers will in most of the cases need to go through demand response service providers (aggregators). These require fair market access for such aggregators and open balancing, wholesale and capacity markets for flexibility products.

a) Market Access for aggregators

The EED stipulates that demand response providers (including aggregators) have to be treated in a non-discriminatory manner. However, market access and market rules for aggregators are regulated differently across Europe. In order to ensure full access to the market at least the following main features have to be addressed in national regulation:

- Clear definition of roles and responsibilities of aggregators within the energy market to ensure legal certainty;
- Clear definition of the relationship between aggregators and Balancing Responsible Parties ('BRPs') that ensures market access of the aggregators at fair conditions. Such rules are essential to ensure that the BRP (which is usually the supplier) has no means of stopping a competitor (e.g. independent aggregator) for engaging with one of its customers and entering the market.

In many Member States such a framework for aggregators is effectively missing or independent aggregation is legally banned. This applies for Bulgaria, Croatia, Cyprus, Czech Republic, Estonia, Greece Italy, Malta, Portugal, Spain and Slovakia. But also in Member States where legislation for aggregators and demand response has been established many differences can be noted.

To date, France is the only Member State that developed a complete framework for demand response explicitly enabling independent aggregation by guaranteeing contractual freedom between the consumer and the aggregator without supplier's consent. A standardised framework also exists for the compensation mechanisms, however, it is claimed by some stakeholders that this mechanism greatly penalises the aggregator, overcompensates the BRP and hence renders the business case for independent aggregators negative.

Other Member States allow (independent) aggregation but to varying degrees. Independent aggregators are allowed in Belgium, Ireland, UK, Germany and Austria albeit not all markets are effectively opened to them as rules, e.g. in Austria, effectively limit their activity to aggregate loads of big consumers. In some Member States like Poland, the Netherlands and in the Nordic markets aggregators have also to become suppliers or offer their services jointly with suppliers but cannot act as completely independent service providers. In all Member States, apart from France, the UK and Ireland, the explicit consent of the consumer's supplier is required for aggregators to enter into the market. Equally in those Member States, a clear framework for compensation payments is missing and therefore such payments may need to be individually negotiated between the independent aggregator and supplier as a precondition for accessing the consumer. As such, the incumbent supplier can effectively block market access at least for independent aggregators.

b) Access of flexibility to the markets

The EED requires Member States to promote access to and participation of demand response in balancing, reserve and other system services markets *inter alia* by engaging the national authorities (or where relevant, the TSOs and DSOs) to define technical modalities on the basis of the technical requirements of these markets and the capabilities of demand response; these specifications must include the participation of aggregators.

Technical modalities or requirements can be for example the minimum size of a load, the activation time or the duration for which a product needs to be provided. Traditionally, requirements have been designed along the capacities of big generation units, e.g. coal power plants. Demand side products naturally face problems to meet these requirements, even if aggregated. Another aspect is that prequalification requirements often have to be fulfilled per unit and not at the aggregated level. As the following stock-taking will show, access of demand resources to the wholesale, balancing and recently capacity markets varies considerably across Member States.

The analysis of the *status quo* suggests that in most of the Member States access to the markets is either up-front restricted or preconditions make it difficult for demand side products to qualify and compete. In roughly only a third of the Member States demand side products have fair access to the markets and in even fewer Member States demand response is actually happening. Generally, the balancing markets tend to be more open to demand side products than the wholesale markets.

In many Member States demand side resources do not play any role in the markets. Examples for this situation would be Cyprus, Malta and Croatia. But also in many other Member States markets are practically closed and allow for only very restricted participation of the demand side. Often it is only suppliers or big industrial actors that are allowed to bid in the markets. In those cases, there are usually very specific demand flexibility programmes for selected, mainly very large, actors. For example, in Italy, Spain and Greece interruptibility programmes have been or are being introduced for large industrial loads.

Other countries are one step ahead and have partly opened their markets, while practical barriers still hamper the market access. The balancing market in Germany for example is in principle open to demand loads, but heavy prequalification (e.g. extensive testing) and programme requirements (e.g. bid size) block any major remand response-activity. Similarly, practical barriers, in particular for aggregated demand, hamper access to the – theoretically open – balancing markets in Slovenia and Denmark and to some degree also in Sweden.

There is a group of countries where demand response has already assumed a more important role. Belgium for example adapted their technical requirements and offers quite a large range of possibilities for demand side resources to participate in the balancing and ancillary services markets. In the UK, the market for ancillary services[93] is open to demand response and a dedicated 'Demand Side Balancing Reserve' mechanism was established in 2015. Meanwhile, France has become probably the Member State with the broadest general access of demand response to both the balancing and the wholesale market. A general framework is in place that facilitates demand side participation, which has caused demand response providers to begin expanding onto this market.

The table below summarizes in which Member States markets are open to demand response and the amount of incentive based demand response currently estimated in those Member States. While demand response is allowed to participate in most Member States, activated volumes of more than 100 GW can only be found in 13 Member States.

Table 1: Uptake of incentive-based demand response

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

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

Implicit (price based) demand response

93 The range of functions which TSOs contract so that they can guarantee system security, including black start capability, frequency response, fast reserve and the provision of reactive power.

For implicit demand response, smart metering systems as well as the availability of dynamic pricing contracts linked to the wholesale market are prerequisites. For smart metering systems roll-out plans exist for 17 Member States, while in 2 Member States a partial roll-out is planned and in a number of those Member States the functionalities of the smart metering systems (enabling communication interfaces, frequent update intervals, advanced tariffication, etc.) may not allow for automatically reacting to price signals (a complete analysis is provided within the evaluation fiche on smart metering). EU legislation does not currently impose any requirements on Member States to activate price based (or implicit) demand response.

In order to activate price based demand response the availability of dynamic electricity pricing contracts are a prerequisite as those contracts can incentivise consumers to adjust their consumption according to the real time price signal. The ACER/CEER Market Monitoring Report contains a dedicated analysis of the competition situation in all Member States in the retail market and the different offers available to the customers. This analysis shows that only in Denmark, Sweden and Finland dynamic pricing contracts that are linked to the spot market are available to residential consumers while only in Sweden and Norway such contracts represent more than 10% of all consumer contracts. In terms of costs for the consumers the ACER/CEER analysis shows that offers linked to the spot market are slightly cheaper for the consumer than fixed or variable offers in the same country.

Graph 1: Type of energy pricing of electricity offers in EU Member States capital cities,

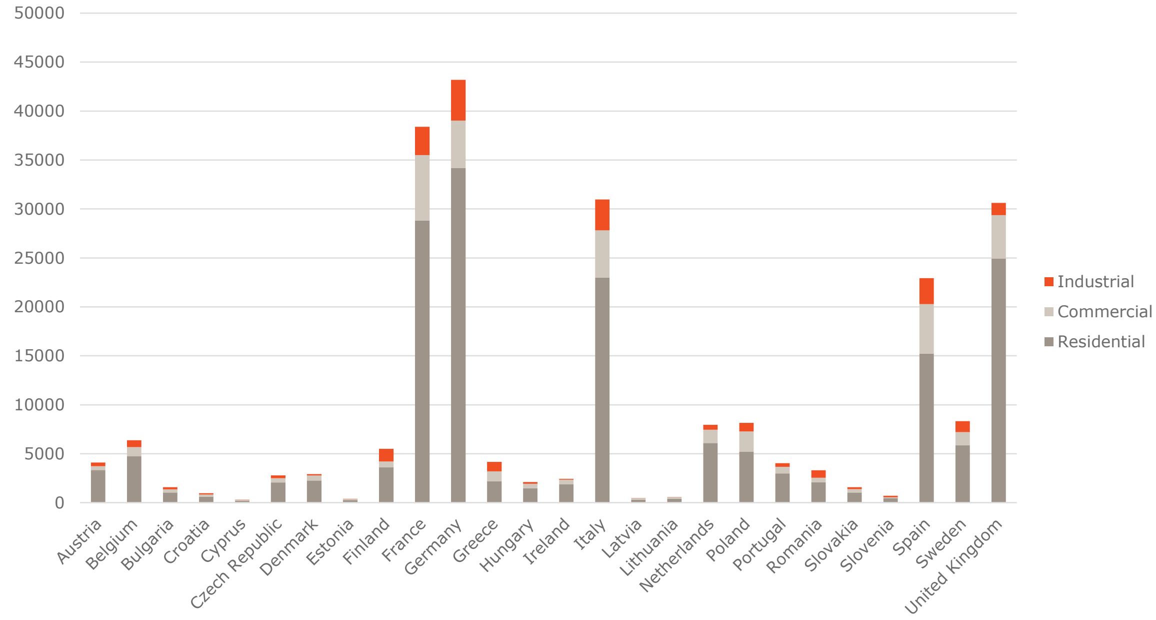
Source: "Market Monitoring Report 2014" (2015) ACER

In addition to the three Member States addressed above also in Estonia, Spain, Austria, Belgium, Netherlands and Germany dynamic pricing contracts are available on the market – at least for certain consumer groups - which were not yet included in the ACER/CEER analysis. However, the uptake of such tariffs is currently very low and no detailed data is available yet.

As a high level estimate for the EU, studies and data support current load shifting due to times of use tariffs and price based demand response ranging from negligible (most Member States), to around 1% (most Northern European Countries) to 6-7% (Finland and France). The overall load that is shifted due to Time-of-Use ('ToU') and dynamic tariffs to date would be of the order of 5.7GW (or 1.2% of peak load in Member States where dynamic tariffs are offered).

While data on current demand response levels is difficult to obtain, estimates from the impact assessment study[94] indicate the use of approx. 21.4 GW of demand response per year in Europe including the 5.7GW from ToU and dynamic tariffs referred to above. This is only a small fraction of the demand response potential that adds up to approx. 120.000 MW in 2020 and 160.000 MW in 2030 which will lay mainly with residential consumers. However, this potential is purely theoretical (not taking into account commercial viability and technology restriction) and for 2030 greatly depends on the uptake of flexible loads such as electric vehicles and heat pumps in the residential sector.

Graph 2: Theoretical demand response potential 2030



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

3.1.3. *Deficiencies of current legislation*

A detailed analysis of the existing legislation on smart metering systems and demand response in European and national legislation has been carried out in the framework of the evaluation. The detailed results of this analysis are reported in the annexes to the Market Design Initiative evaluation (annexes on "Details on the EU framework for smart metering roll-out and use of smart meters" and "Details on the EU framework for Demand Side Flexibility")

[94] *"Impact Assessment support Study on downstream flexibility, demand response and smart metering"*, (2016) COWI

3.1.3.1. Deficiencies of current Smart Metering Legislation

Looking at the current situation with smart metering deployment in the Member States, despite the progress noted, EU-wide implementation is falling short of the legislator's intentions, in terms of level of commitment, roll-out speed, and purpose. In the light of the developments so far, the existing provisions can be assessed as follows.

In terms of **effectiveness**, the evidence available generally suggests that the smart metering provisions currently in place have been less effective than intended. This is partly a result of the 'soft'/unspecific nature of some obligations they lay (i.e. Article 8(2) of the EPBD. Enforcing the recommended[95] minimum functionalities for smart metering systems on an EU level, and consistently promoting the use of available standards to ensure connectivity and '*interoperability'*, as well as best practices, while having due regard to data security and privacy, would guarantee a coherent, future-proof system able to support novel energy services and deliver benefits to consumers, in line with the legislator's intentions.

There is not enough evidence at the moment to evaluate the **efficiency** of the intervention in terms of proportionality between impacts and resources/means deployed. This is due to the fact that most of the large-scale roll-out campaigns have yet to start unfolding making the field data available rather scarce; there are only projections available based on Member States cost-benefit assessments.

In terms of **relevance**, the evaluated smart metering provisions, considering current needs and problems, remain highly valid. This said, they could though be further enhanced, by elaborating them as to: (i) spell out how the term of *'active participation'* is to be understood, and expected to be realised in practical terms, namely define requirements for functionality, connectivity, interoperability, and standards to use; (ii) include an obligation to Member States to officially set the minimum technical and functional requirements for the smart metering systems to be deployed, the market arrangements, and clarify the roles/responsibilities of those involved in the roll-out.

In terms of **coherence** – internally and with other EU actions – even though no clear contradictions could be pointed out, the evaluation has identified some room for improvement. Linking of the term *'actual time of use'* in Article 9(2a) and Article 9(1) EED to smart metering provisions erroneously restricts the functional requirements of the targeted set-ups and raises questions about coherence with the framework for promoting smart meters. There is therefore a need to clarify that a wide range of functionalities is in fact promoted, as those recommended by the Commission, that go much beyond the capability of just *'actual time of use'* information which usually refers to advanced, and not smart metering.

Finally, evidence points to the need to eliminate ambiguities and to further elaborate, clarify, and even strengthen the existing provisions, in order to give certainty to those planning to invest and ensure that smart metering roll-outs move in the right direction, and regain **EU added-value**. This is to be done by: (i) safeguarding common functionality, and share of best practices; (ii) ensuring coherence, interoperability,

95 *Commission Recommendation on preparations for the roll-out of smart metering systems (2012)* http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32012H0148

synergies, and economies of scale, boosting competitiveness of European industry (both in manufacturing and in energy services and product provision); and (iii), ultimately delivering the right conditions for the internal market benefits to reach also consumers across the EU.

3.1.3.2. Deficiencies of current regulation on demand response

It was the objective of the existing European legislation to put demand response on equal footing with generation and to ensure that demand response providers, including aggregators, are treated in a non-discriminatory way. While provisions aiming at realising those objectives have been put in place in many Member States, the development of demand response across Member States varies significantly and has led to fragmented markets. Especially the different treatment of independent aggregators across the EU is a matter of concern. It can therefore be concluded that additional provisions further specifying the existing provisions are needed to ensure a harmonised development and enable price and incentive based demand response across Europe.

In terms of **effectiveness**, the evidence available generally suggests that the demand response provisions currently in place have been less effective than intended. The provisions have not been effective in removing the primary market barriers especially for independent demand response service-providers and creating a level playing field for them. Instead the heterogeneous development of demand response has led to fragmented markets across the EU. This is mainly due to the high degree of freedom the existing provisions leave to Member States. The different treatment especially of independent demand response service-providers in national energy markets as well as of flexibility products in electricity markets risk undermining the large-scale deployment of demand response needed as well as the functioning of the internal energy market.

There is not enough evidence at the moment to evaluate the **efficiency** of the intervention in terms of proportionality between impacts and resources/means deployed.

In terms of **relevance**, the herein evaluated demand response provisions remain highly valid. Full exploitation of demand response remains crucial to manage the energy transition as it is an enabler for efficiently integrating variable renewables into the energy system. However, as pointed out above, the existing provisions have not been effective in deploying demand response sufficiently quickly across Europe.

In terms of **coherence** the evaluation has shown that the provisions on demand response are fully coherent with other legislative provisions within the Electricity Directive, the EED, the RED and the EPBD.

Finally, considering the **EU added value**, it remains crucial to ensure that harmonised demand response provisions are in place across the EU to guarantee a functioning internal energy market. Even more because under the upgrading of the wholesale market within the market design initiative the Commission will also look into opening national balancing markets where flexibility may then be traded across borders. Full availability of demand response in all Member States will then be crucial for the functioning of those cross-border balancing markets.

3.1.4. *Presentation of the options*

Option 0: BAU

As outlined in chapter 3 the existing provisions on smart meters and demand response have not proven to be fully effective in reaching the goals of rolling out fully functional smart metering systems to at least 80% of consumers EU-wide by 2020 and to put demand response on equal footing with generation.

Option 0+: Non-regulatory approach

Considering non-legislative intervention and just resorting to Option 0+ of a potential stronger enforcement and/or voluntary cooperation, would not allow for an improvement of the current situation regarding the uptake of fit-for-purpose smart metering and of the market conditions for demand response to flourish. Option 0+ is not expected to remove market barriers for demand side flexibility to reach its full potential, and therefore will not deliver the policy objectives.

According to the Commission's assessment, the provisions related to smart metering systems have been correctly transposed in Member States and hence, as argued earlier, no further enforcement leading to a greater roll out of such systems is realistic. The provisions of Art 15(8) EED related to demand response have not yet been subject to a full transposition check or any infringements. However, even in those Member States where the provisions have been fully and correctly transposed market barriers for independent service providers continue to exist. This suggests that the current provisions are not sufficiently explicit to fully remove all remaining barriers to demand response. As such a stronger enforcement of existing provisions may in some Member States lead to a greater take up of demand response but this alone will not be sufficient to provide a full level playing field as intended by European legislation, and would not deliver the policy objectives, which is the reason this option was not further considered.

Option 1: Enable price based demand response

Smart metering systems are the key prerequisite for properly accounting for, and then rewarding, consumers' involvement in demand response or the use of distributed energy resources. However, it is expected that a smart meter roll-out will be realised in only 17 Member States (plus a partial roll-out in 2 Member States). In some of those Member States the roll-out may take place without all the functionalities identified in the Commission Recommendation on the preparations for the roll-out of smart metering systems.

Our objective is to ensure that interoperable smart metering systems with the right functionalities are available to all consumers. The policy measures to ensure that price based demand response can develop include:

- Give consumers the right to request a meter with the full 10 functionalities when roll-out without full functionality is taking place or has already been completed.

- Give consumers the right to request a smart meter with full functionalities when wide scale roll-out is not carried out[96].
- Grant consumers the right to an electricity pricing contract linked to the development of the spot market.

Option 2: Enable price and incentive based demand response across Europe

In addition to enabling price based demand response schemes as in Option 1, the objective in this area is to remove the key barriers to incentive based demand response and flexibility services in order to facilitate the market-driven deployment of these technologies to the greatest practicable and economically viable extent. The new rules ensuring full market access for independent aggregators will address the following:

- Ensuring full non-discriminatory market access for consumers to all relevant markets either individually or through third part aggregators.
- Ensuring that each market participant contributes to the system costs according to the costs and benefits (s)he induces to the system.
- Removal of barriers at wholesale, balancing at capacity markets for aggregated loads and for flexibility.

Option 3: Mandatory smart meter roll-out and full EU framework for incentive-based demand response across Europe

The third option goes beyond the provision in Option 2. Instead of the right for consumers to request a smart meter, it contains an obligation for a mandatory roll-out of smart meters with the 10 recommended functionalities by 2025, for 80% of consumers in every Member State. In addition, it contains a detailed framework for demand response that no longer only defines principles for this framework but also defines favourable financial rules for aggregators: The financial arrangements between aggregators and BRPs explicitly exclude any financial transfers between aggregators and BRPs. The provisions on access of aggregated loads to wholesale, balancing and capacity markets remain unchanged from Option 2.

[96] In both cases the requested systems must be able to ensure interoperability among the operators responsible for metering and other participants in the electricity market and thus support the provision of energy management and information services of benefit to the consumer.

3.1.5. *Comparison of the options*

a. Effectiveness of options

In the context of this impact assessment two objectives are envisaged:

- The accelerated deployment of fit-for-purpose smart metering systems that will enable consumers to receive timely and accurate information on which they can promptly act and accordingly adjust their consumption – in volume and time –and benefit from new energy services (e.g. demand response)

- The uptake of demand response for consumer and system benefit

Smart Metering uptake

Assuming that no new EU intervention takes place, apart from the stronger enforcement of existing legislation which is foreseen under **option 0**, and deployment plans go ahead as they currently stand, smart meters will be installed only in those Member States where their deployment is currently positively assessed, leading to a maximum EU penetration rate of close to 72% by 2020. However, the systems to be rolled out will not necessarily be interoperable, nor equipped in all cases, as recent data have shown[97,98], with those consumer benefitting functionalities (as listed in "Commission Recommendation on preparations for the roll-out of smart metering systems") that support his participation in novel energy services' programmes.

It is important to note here that increased functionality is directly associated to benefits, but not to costs; it does not push up the overall cost of the deployment, given that it is mainly software driven and its incremental cost is relatively low[99]. Issues related to economies of scale and customisation may be more important in driving overall costs. So, selecting fewer items from the set of common minimum functionalities does not necessarily translate into less expensive systems. This makes a compelling case for adhering from the start of the roll-out to the full set of the recommended functionalities[100] for the smart metering systems rolled-out.

Bearing in mind the intentions of the Member States regarding smart metering functionalities, and for rolling out standardised interfaces to support the communication of the metering infrastructure with devices and business platforms, in practice, much

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97 Commission Staff Working Document *"Cost-benefit analyses & state of play of smart metering deployment in the EU-27"* (2014) Table 8

98 *"Status report based on a survey regarding Interoperability, Standards and Functionalities applied in the large scale roll-out of smart metering in EU Member States"* (2015) Smart Grids Task Force Expert Group 1

99 *"Cost benefit analysis of smart metering systems in EU Member States"* (2015) ICCS-NTUA & AD Mercados EMI ; *"Impact Assessment support study on downstream flexibility, demand response and smart metering"* (2016) COWI

100 Report from the Commission *"Benchmarking smart metering deployment in the EU-27 with a focus on electricity"* (2014) http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2014%3A356%3AFIN; supported with data from the Commission Staff Working Document "*Cost-benefit analyses & state of play of smart metering deployment in the EU-27"* (2014) .

more than 30% of EU customers by 2020 will be effectively denied the means – a fully functional smart metering system - for getting involved in demand response schemes. Furthermore, given that the meters installed will be in place for the next 15 years, which is their average economic lifetime, the overall demand response potential will be significantly reduced up to 2030.

For estimating the smart metering deployment for the alternative **Option 1** (smart meter or its functional upgrade on request by the consumer) the following assumptions are made:

- In countries with a reported large-scale roll-out of smart metering systems, the roll-out occurs as planned, with the recommended functionalities not being though throughout implemented. In all cases, customers will have access to dynamic tariffs by 2020. This reflects greater customer and supplier awareness of the benefits of smart meters;
- In countries with either a limited (in terms of customer coverage or functionality) roll-out or no planned roll-out, fully functional smart meters (or their upgrade) will be made available to customers on demand.

The extent to which customers will choose the installation of a smart meter (or its functional upgrade) will depend on a range of factors, including the proportion of overall benefits that it could capture for them. Where a customer is faced with the full cost of smart metering installation, extremely low take up is envisaged in the relevant Member States based on current technology and its cost.

The analysis of national cost-benefit analyses for the roll-out of smart meters in those countries not proceeding with a large scale roll-out has shown that customer related benefits from smart metering systems are generally significantly lower than corresponding per metering point costs. In two cases (Germany and Slovakia) the national CBAs have concluded that a mandatory roll-out to all consumers would not be beneficial but only for consumers above a certain consumption threshold:

- In Germany a mandatory roll-out for all consumers with an annual consumption above 6000kWh is proposed;
- In Slovakia, the CBA considers that consumers with annual consumption above 4000kWh (covering 23% of metering points and 53% of Low Voltage consumption) will overall benefit from an installation.

For the purpose of analysis, it is assumed that for all countries without a full purpose (in terms of scale - nationwide, and function) roll-out of smart meters, the uptake of a smart meter paid for by the consumer will be low in the short to medium term (up to 2020), but may well increase significantly in the subsequent period to 2030 as the costs of meters, communications and information technology fall, and the spread of appliances conducive to price-based demand response rises. Therefore, the following estimates are made:

- Take up of smart meters of around 10% of residential and small commercial consumers by 2020 in Member States where no full purpose roll-out is planned;
- Take up of smart meters of 40% of residential and small commercial consumers by 2030 in Member States where no full purpose roll-out is planned.

While no additional smart metering related measures are foreseen under **Option 2**, under **Option 3** a mandatory roll-out of smart meters to at least 80% of consumers in all Member States is included, and this is to materialise irrespectively of the result of their national assessments for the cost-effectiveness and feasibility of this deployment. Such a mandatory roll-out will eventually lead to approximately 90% of all consumers having a fully functional smart metering system installed by 2030. This reflects current experience with smart metering roll-out where some installations for technical reasons may be too expensive and some consumers refusing to have a smart meter installed because of privacy concerns.

In the light of these assumptions, the resulting estimates of smart meter roll-out and access to dynamic tariffs under Option 1, 2 and 3 are set out below.

Table 2: Overview smart meter uptake

	BAU = Option 0	Option 1	Option 2	Option 3
2016				
Smart meter	35%	35%	35%	35%
2020				
Smart meter	71%	72%	72%	72%
2030				
Smart meter	74%	81%	81%	90%

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

Uptake of dynamic price contracts

In order to participate in price based demand response schemes, consumers not only have to have a smart meter but also a dynamic electricity price contract. Under all options, it is considered that the consumer must voluntarily opt in for such a contract. At this stage, only estimates can be made on the number of consumer with a smart meter opting for dynamic contracts, time of use contracts and static contracts. The following estimates have been used for this analysis on the basis of various studies as well as pilot projects and initial experience in the Nordic countries[101]:

[101] The core estimated figures are in line with international trial studies and practical evidence, including:
- The consumer survey of "*Smart Energy GB survey*", which states that around 30% of the people were either strongly or moderately in favour of switching to a ToU tariff;
- The take-up rate of the Critical Peak Pricing ("CPP") tempo tariff in France that was slightly less than 20% of the total consumers.

Table 3: Uptake of dynamic and ToU price contracts of consumers with smart meters

	BAU	Option 1	Option 2	Option 3
2016 ToU Dynamic	 10% 0%	 10% 0%	 10% 0%	 10% 0%
2020 ToU Dynamic	 18% 3%	 18% 3%	 18% 3%	 18% 3%
2030 ToU Dynamic	 26% 16%	 26% 16%	 26% 16%	 26% 16%

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

The average uptake rate is identical for all options as for all options it is assumed that dynamic tariffs are available for those consumers who wish to have one. In the case of Member States not currently planning a large scale roll-out of smart metering systems and for which optional take up applies under Option 1, a higher take up rate is assumed for the calculation. This is done under the assumption that consumers actively opting for smart meters are equally more likely to actively opt in for advanced price contracts. Hence the take up rate for static ToU and Critical Peak Pricing (CPP) doubled in 2020 and 2030 for customers with a smart meter (52% and 32% respectively in 2030).

Demand response uptake

The uptake of demand response was calculated on the basis of the smart meter roll-out and uptake of dynamic price contracts as presented above taking into account the overall demand response potential as presented in chapter 3.1.2.

Option 0 (BAU)

In case no additional measures are taken demand response will still develop across Europe. The roll-out of smart meters will be carried out as planned and dynamic price contracts will be available to consumers in Member States where mart meters are rolled out and where the retail market is sufficiently competitive. Under the BAU, an increase of price based demand response from 5.8 GW to 15.4 GW in 2030 is accepted.

It is important to note that the uptake of demand response depends heavily on the appliances/loads residential consumers have in their possession:

- For normal appliances, 4.9% of potential demand response is captured, while
- For electric vehicles, heat pumps and smart appliances, 18.6% of potential demand response is captured.

These figures are very sensitive to the take-up of new forms of price contracts. The proportion of potential demand response for electric vehicles and heat pumps captured ranges from around 13% for Member States not currently supporting a widespread roll-out of smart metering systems to around 21% if it is planning a full scale roll-out.

Incentive-based demand response will only develop very slowly as in the absence of a clear enabling framework independent aggregation will remain limited and access of flexibility to the markets limited. In total, under the BAU option demand response can increase from 21.4 GW in 2016 to 34.4 GW in 2030 or by 60%.

Option 1

In case only price based demand response is further enabled, the calculation shows that total demand response would only increase compared to the BAU by approx. 2.5 GW by 2030 at an EU-wide level. This reflects the moderate additional uptake of smart meters when each consumer has the right to have it installed.

Option 2

Incentive-based demand response is already represented in the wholesale energy markets in half of the Member States. In policy Option 2, it is assumed that all Member States having introduced some incentive based demand response already will reach a level of 5 per cent peak reduction in 2030, gradually increasing from today's level. The increased level of demand response compared to Option 1 is due to adjustments in programme requirements to better reflect the needs of demand side. This includes allowing aggregated bids in the markets allowing aggregators enter the market as a service provider for industry and large commercial consumers. There is also a standard process for settlements between aggregators and suppliers to facilitate aggregation. Also, all Member States will introduce incentive based demand response and the Member States not currently having incentive based demand response, will reach a level of 3 per cent of peak load in 2030, the potential gradually being introduced from 2021. The reasoning for take-up of demand response in these Member States is the same, but they will start from a lower level than Member States where demand response is already taking place.

Those measures will lead to an increase of incentive based demand response by approx. 15.6 GW or more than 80% compared to the BAU scenario. Under option 2 price based demand response stays stable as no additional measures are introduced. Hence, total demand response compared to the BAU scenario will increase by approx. 18GW or 52%[102].

Option 3

In policy Option 3 it is assumed that all Member States having already introduced some incentive based demand response will reach a level of 8 per cent peak reduction in 2030, gradually increasing from today's level. Also, all Member States will introduce incentive-based demand response and the Member States not currently having incentive based demand response, will reach a level of 5 per cent of peak load in 2030, the potential gradually being introduced from 2021. The increased level of demand response compared to Option 2 is due to aggregators entering the market as a service provider under more favourable conditions. Also, the prices for balancing reserves have increased due to increased imbalances in the energy market. Those measures will lead to an increase of incentive based demand response by approx. 20 GW or approximately double compared to the BAU scenario.

102 In this Impact Assessment only the impact demand response is being quantified. Other forms of consumer flexibility such as self-generation are being assessed under the RED II Impact assessment.

Under this option it is assumed that price based demand response will remain unchanged. While more consumers will have access to a smart meter it is unlikely that those additional consumers who have not opted for a smart meter in the first place will request a dynamic tariff and hence they will not participate in demand response schemes. Total demand response compared to the BAU scenario will therefore increase by approx. 23GW or 66% or by 4.7GW compared to Option 2.

Table 4: Overview of demand response (in GW/year) uptake for different options

	BAU	Option 1	Option 2	Option 3
2016				
Price-based	5.8	5.8	5.8	5.8
Incentive-based	15.6	15.6	15.6	15.6
Total	**21.4**	**21.4**	**21.4**	**21.4**
2020				
Price-based	6.4	6.9	6.9	6.9
Incentive-based	16.3	16.3	20.3	21.4
Total	**22.7**	**23.3**	**27.2**	**28.4**
2030				
Price-based	15.4	17.9	17.9	17.9
Incentive-based	19.0	19.0	34.6	39.3
Total	**34.4**	**36.8**	**52.4**	**57.1**

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

b. Key economic impacts

Cost and benefits of smart metering

In this Section the cost-effectiveness and impact of smart metering is to be seen as part of the bigger picture of delivering services to the consumer and enabling his participation in price based demand response, and allowing him to offer his flexibility to the energy system, and be rewarded for it.

Under **option 0**, the smart metering roll-out, following in most cases a positive CBA undertaken by the Member States, is assumed to take place as planned. A complete listing of *costs* and *benefits* associated with smart metering deployment in Member States can be found in the Commission Benchmarking Report issued in 2014[103]. Available data there coming from the CBAs[104] of Member States that are proceeding with the roll-out,

[103] (see Table 25 in) Report from the Commission *"Benchmarking smart metering deployment in the EU-27 with a focus on electricity"* (2014) http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2014%3A356%3AFIN; and accompanying (i) Commission Staff Working Document *"Cost-benefit analyses & state of play of smart metering deployment in the EU-27"* (2014), (ii) Commission Staff Working Document *"Country fiches for electricity smart metering"* (2014)

[104] idem

indicate, despite their divergence, that the cost of installing a smart metering system for electricity is on average close to EUR 225 per customer, while the benefit (per customer) is EUR 309 accompanied by energy savings in the order of 3% and up to 9.9% of peak load shifting.

The peak load shifting expectations vary greatly across the Member States; namely from 0.75% (UK) and 1% (Poland) to 9.9% in Ireland in the cluster of Member States that are preparing a roll-out, and from 1.2% (Czech Republic) to 4.5% quoted in Lithuania in the batch of Member States that are not presently proceeding with large-scale deployment. These significant differences may be due to: (i) different experiences coming from locally run pilot projects and/or hypotheses adopted in building the scenarios;[105], and (ii), different patterns considered in electricity consumption, e.g. presence of district heating, wide-spread use of gas, etc.

On the *cost side*, meter costs (CAPEX and OPEX) are identified by the majority of Member States as dominant followed by the capital and operational cost due to data communication. In most countries (and relative to the electricity deployment arrangement of the country), the smart metering investment and installation cost appears as an upfront cost for the distribution system operator in the initial stage of the deployment; however, in most cases they are later fully or partly passed to the final consumer through network tariffs.

Regarding *benefits*, data show that in a number of Member States – the Czech Republic, Denmark, Estonia, France, Italy, Luxembourg and Romania – the distribution system operator is the first/large direct *beneficiary* of the electricity smart metering, followed by the consumer, and the energy supplier. The associated benefits have little to do with demand response, and are related to administrative improvements in the areas of meter reading, dis/re-connection, identification of system problems, fraud detection, as well as increased customer services. Finally, other benefits can also be linked to smart metering such as CO_2 emissions reduction due to first energy savings, as well as more efficient electricity network operation (reduced technical and commercial losses); these result in benefits accrued to the whole society.

It is important to note that to obtain full benefits, particularly consumption-related ones, greater meter functionality is required. Yet, the CBAs show no direct link between cost and functionality[106]. So, asking Member States to give under **Option 1** and **Option 2** the entitlement to consumers to request a smart meter with full functionality, or the upgrade of an existing one, should not pose any disproportionate costs on top of the meter unit cost. However, the fact that smart meters will end up being rolled out on customer-per customer basis will not allow reaping in full system-wide benefits or benefits of scale and will lead to higher per unit cost/benefit ratios.

[105] e.g. consumers' participation rate in demand response programmes (time-of-use pricing, etc.), different consumer engagement strategies (e.g. indirect vs. direct feedback)

[106] Report from the Commission *"Benchmarking smart metering deployment in the EU-27 with a focus on electricity"* (2014); also confirmed in (i) *"Cost benefit analysis of smart metering systems in EU Member States"* (2015) ICCS-NTUA & AD Mercados EMI; and (ii) *"Steering the implementation of smart metering solutions throughout Europe: Final Report"* (2014) FP7 project Meter-ON, p.9 and p.11; http://www.meter-on.eu/file/2014/10/Meter-ON%20Final%20report-%20Oct%202014.pdf

In those countries where a large-scale roll-out is currently not foreseen and additional meters are to be installed on customers' request, under **Option 1** and **Option 2**, the total investment for installing additional meters could – as a first approximation - reach EUR 5 billion by 2030[107] for a penetration rate of 81% (compared to 74% in BAU). Half of these costs for the installation of additional meters could potentially be offset by benefits (for example lower costs/avoided costs of meter reading and operation, reduced commercial losses[108]) other than those related to demand response[109]. As a result, the total cost by 2030 for the installation of these additional meters requested by consumers within the EU – under Option 1 and Option 2 – could go down to EUR 2.47 billion; this corresponds to an annual cost of EUR 215 million, for a period of 15 years (which is the average economic lifetime of smart meters) considering a discount rate of 3.5%.

A similar calculation could also be undertaken for **Option 3** which will enforce the roll-out of smart metering in all cases including those where deployment was found to be non-beneficial according to the national economic assessment of long-term costs and benefits. In this case, a mandatory roll-out throughout the EU could result in achieving ultimately a penetration rate of 90% by 2030, and the additional smart metering installation costs could rise beyond EUR 14 billion[110]. This figure represents the additional cost should a mandatory smart meter roll-out is obligated throughout the EU. Half of these costs, as argued earlier, could potentially be balanced by benefits linked to lower costs for meter reading and operation and avoided commercial losses[111]. Consequently, the total additional investment is halved, and the corresponding 'net' annual cost (for 15 years modelling period, at 3.5% rate) is estimated at EUR 613 million (per year).

The tables below present the specific costs of additional meters installation, on consumer request or obligated by legislation (Option 3), calculated per Member State, for the alternative options considered.

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107 The calculation is based on the projected smart metering penetration rate by 2030, and on an average cost per metering point of EUR 279. This value is worked out from data of Member States' CBAs – both positive and negative in their outcome - that were analysed under the "*Study on cost benefit analysis of Smart Metering Systems in EU Member States-Final Report"* (2015) AF Mercados EMI and NTUA, and presented on Table 8, p. 26 of the aforementioned report. This average value of EUR 279 per metering point includes the smart meter costs, the information technology cost, communications costs and costs for the installation of an In-Home Display (in the case of two Member States cost-benefit analyses).
Note – The accuracy of this calculation depends on the extent that a fixed cost (which is the total cost for rolling-out to 80% of population) can be proportionately shared, and accordingly deployed to derive the 'unit cost', which is then used to estimate, for any penetration rate, the cost of installation of smart metering.

108 see Figure 4, page 34 of the "*Study on cost benefit analysis of Smart Metering Systems in EU Member States-Final Report"* (2015) AF Mercados EMI and NTUA.

109 *"Impact Assessment support Study on downstream flexibility, demand response and smart metering"* (2016) COWI.

110 *Idem*

111 *idem*

Table 5: Overview of estimated costs for additional smart meter installation by 2030, considering options 1 and 2

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

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

Table 6: Overview of estimated costs for additional smart meter installation by 2030 considering Option 3

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

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

Table 7: Overview of estimated 'net' yearly costs for additional smart meter installation by 2030 considering all alternative options

	BAU = Option 0	Option 1, Option 2	Option 3
2030			
Smart meter (penetration rate)	**74%**	**81%**	**90%**
Additional 'net' cost (considering 15 years, at 3.5%)		**EUR 215 million/year**	**EUR 613 million/year**

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

Cost of demand response

To make demand response and its benefits possible, certain investments in the system are necessary and operational costs will incur. For the activation costs of demand response three classes are defined:

Table 8: Overview of cost components for demand response

Parameter	Cost component	Unit
Variable costs	Costs for loss of production, inconvenience costs, storage losses	EUR/kWh
Annual fixed costs	Information costs, transaction costs, control costs	EUR/kW
Investment costs	Installation of measurement-equipment, automatic measurement for control, communication equipment	EUR/kW

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

Variable costs for demand response are the costs incurred at the consumer for offering demand response. In case of load shifting these costs are considered to be zero since the lost output can be produced later. However, it is possible that demand response causes additional costs for inconvenience or efficiency losses due to partial load operations, however these costs are expected to be minor and not possible to quantify and are therefore not considered in this analysis.

The annual fixed costs are incurred on a regular basis and are not related to the actual use of demand response. Predominantly, these costs relate to administration and to incentivise consumers for demand response. This analysis only focusses on the system costs, therefore the annual fixed costs are assumed zero.

Investment costs are incurred once the demand response potential is activated. Costs of this type include

- Investments in communication equipment both at the consumer side as in the grid. This enables remote sending of instructions to the consumers who then can provide demand response.
- Investments in control equipment are needed to carry out load reductions automatically. With control equipment it is possible to provide demand response upon receipt of a signal.
- Metering equipment is required to be able to verify that the load reduction is achieved.

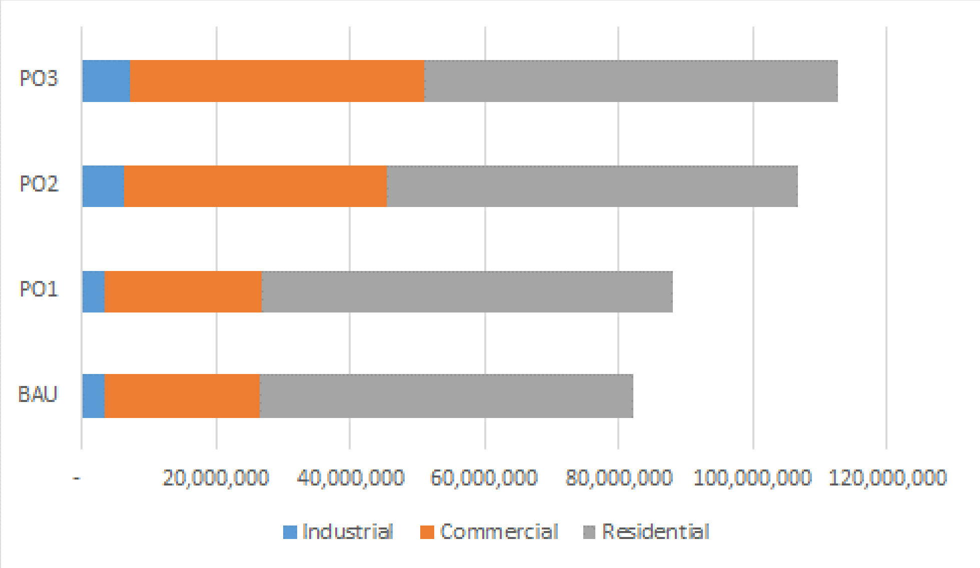
At the moment there is relatively little information available of these investment costs for demand response. Per consumer type, the following assumptions were made:

- **Industrial** consumers often already have equipment installed that can activate demand response. On average, it is however assumed that a very small investment is still required. According to available literature[112], the investments are estimated to be 1 EUR/kW.
- To enable demand response for **residential** consumers, smart appliances must be installed. This means the costs of appliances will be higher. Currently, most new appliances already have an electronic controller which can make the appliance "smart". However, the appliance also has to be equipped with a communication module, which will typically be either a power line communication (PLC) or a wireless module (such as WLAN or ZigBee). It is assumed that due to mass production of smart appliances in the future, the additional costs will be between 1.70 EUR and 3.30 EUR for all appliances that enable smart operation. Furthermore, costs incur for the smart appliance to communicate with a central gateway in a building. This can be integrated into a smart meter or can be offered as a separate device. The gateway enables communication between the residential consumer and an external load manager or aggregator. The link between the appliances and the gateway (power line or wireless communication) does not require the installation of additional wires. Small additional costs can be assumed due to electricity consumption as a result of standby mode of smart appliances. This is assumed to increase the electricity consumption of the appliance between 0.1% and 2%.
- For **commercial** consumers, the costs for demand response are not available in the literature. Therefore, the costs are derived from the costs of demand response for residential consumers. Because the electricity consumption of commercial consumers is on average higher than the electricity consumption of residential consumers, more load can be shifted. As a result, investments are lower per kW/year. An assumption is made that the costs for commercial consumers will be a factor 6 lower.

In the graph below, the costs of demand response are visualized per Option. As can be seen, the costs are mostly related to the residential sector. This is a result of the higher price per kW that is required to activate demand response.

112 *"Quantifying the costs of demand response for industrial business"* (2013) Anna Gruber, Serafin von Roon

Graph 3: Costs of demand response in 2030 – comparison of options



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

Benefits of demand response

Demand response is expected to decrease the peak demand and thereby the maximum needed back-up capacity in the electricity market. The value of a decrease in back-up capacity is expressed as a decrease in yearly CAPEX and fixed OPEX as a function of installed capacity. Demand response also diminishes variable OPEX. When residual electricity demand[113] is averaged (flattened) by demand response, less back-up power needs to be generated by back-up units high in the merit order, and the variable costs of electricity generation will be reduced. Together the decrease in fixed and variable costs determine the estimated value of a demand response option in the electricity market.

Table 9: benefit of demand response for reduced back-up capacity in 2030

	BAU	Option 1	Option 2	Option 3
Total demand response potential 2030 (GW)	34.4	36.8	52.4	57.1
Total Value demand response (million EUR/y)	3517	3772	4588	4736

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

In the distribution grids, demand response options can be deployed to reduce the peak, and thereby the required capacity, in the distribution and transmission networks. These benefits are reflected in a lower required investment in these grids. The benefits shown in the column 'distribution and transmission' in the table below are estimated based on existing literature on this topic in combination with the calculations of the overall

113 Residual demand is the demand that remains after subtracting intermittent sources like solar and wind.

possible peak reduction as calculated for the system level. It is shown in modelling exercises that to a large extent peak reduction at the system simultaneously reduces peaks in the distribution grids. This makes this peak demand reduction a good starting point for estimating the savings in the grids.

To estimate the savings per kW of peak capacity reduced, one needs to distinguish between demand connected on the lower voltage and higher voltage grids. The savings on the higher voltage are lower because only investments in transmission can be avoided. It is assumed that industrial demand is on the higher voltage grids, while domestic and commercial demand response is connected to the medium or lower voltage grids.

The average savings are used to calculate the savings that are made possible by the peak reduction. The results are presented in the table below.

Table 10: Benefits of demand response in the distribution and transmission grid

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

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

Overall monetary cost and benefits for all Options

On the basis of the costs and benefits as presented above the net benefit of the different options is calculated as summarised in the table below.

Table 11: Costs and benefits of Options for 2030 (in million EUR/year)

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

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

Using the approach described above, the net benefits of the alternative Options compared to BAU amounts to about 120 MEUR/y for Option 1230 MEUR/y for Option 2 and around 1430 MEUR/y for Option 3. The net benefit includes the estimated savings in generation and network capacity.

What is not included in the estimation of the benefits are the possible effects on system costs, if the independent demand aggregators are free riders not baring any balancing responsibility and hence risk to activate the demand response in an inefficient way: for example by bidding in the wholesale market but in the balancing markets where the price might be higher. This could happen under Option 3 where no compensation between aggregators and BRPs is foreseen, and hence the aggregators have no incentive to achieve balance as early as possible in order to improve the overall efficiency.

What is equally not directly included in this calculation are reduced electricity prices in the wholesale market due to demand response. However, those cost reductions are indirectly included in the reduced generation costs.

The follow-on or indirect effects depend on how the savings are distributed among the different actors. In competitive retail markets the major share of these savings will go into lower electricity bills for the consumers. Lower electricity costs will increase welfare for the residential consumers and increase competitiveness for industrial and commercial consumers. However, in less competitive markets suppliers may profit from those price reductions.

CO_2 emission reductions

Next to the monetary impact also CO_2 reductions can be achieved through a greater uptake of demand response. Those impacts can add up to additional savings 1.5Mton/year by 2030 compared to the BAU scenario.

Table 12: Impact on CO_2 – reduction in CO_2 emissions in Mton/y

	BAU	Option 1	Option 2	Option 3
Reduction in CO_2 emissions in Mton/y	12.4	13.0	12.7	12.4[114]

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

c. Simplification and/or administrative impact for companies and consumers

The measures proposed under Option 2 and 3 are designed to reduce market barriers for new entrants and provide a stable framework for them under which they can operate in the market. This is a necessity for new entrants who currently face great difficulties entering the markets as incumbent suppliers do not allow them to engage with their customers. The removal of such barriers is especially important for start-ups and SMEs who typically offer innovative energy services such as demand response.

114 For options 2 and 3 the CO_2 benefits are less than for option 1, even if their total DR potential is higher. This can be explained as follows: By applying DR, the peak demand will be diminished and less power is generated by back-up units high in the merit order (e.g. gas plants). But at the same time some low demand values will become higher after DR is implemented (we assume the total demand does not change) and more power is generated by back-up units lower in the merit order (e.g. lignite plants).

Equally for consumers all measures are designed to facilitate their access to innovative products and services. Those measures should reduce the administrative impact for consumers to get a fully functional smart meter and sign service contracts with third parties. At the same time the measures also require Member States to clearly define roles and responsibilities of aggregators which also increases confidence for consumers in their services and contributes to consume protection.

Moreover, thanks to a wider deployment of smart metering, under options 1, 2, and particularly Option 3, the distribution system operators will be in a position to lighten and improve some of their administrative processes linked to meter reading, billing, dis/reconnection, switching, identification of system problems, commercial losses, while at the same time offer increased customer services. Furthermore, a wider roll-out of smart metering would allow TSOs to better calculate, and improve their processes, for settlements and balancing penalties as the consumption figures can be based on real consumption data and not only on profiles.

d. Impacts on public administrations

Regarding **smart metering**, there will be impacts on public administration, namely on the Member States' competent authorities including the national regulators.

Those 17 Member States that roll-out smart meters will not be affected by provisions on smart meters, under **all options,** apart from the obligation to comply with the recommended functionalities, which they may need to transpose into national legislation. Similarly, those two Member States that opted for partial roll-out are not expected to face any major additional impacts from allowing additional consumers to request smart meters, under **Option 1 and 2**. However, they will be impacted when enforcing a mandatory roll-out under **Option 3** which will require substantial changes in their legislation as it currently stands. The remaining Member States that currently do not plan to install smart metering in their territory will need to establish legislation with technical and functional requirements for the roll-out – under any of the options – and face some additional administrative impact for re-evaluating their cost-benefit analyses.

Similarly, additional administrative impact may be created for the national regulatory authorities (NRAs) for enforcing actions regarding the consumer entitlement to request a fully functional smart meter. This includes assessing the costs to be borne by the consumer, and overseeing the process of deployment. At the same time, improved consumer engagement thanks to smart metering, would make it easier for NRAs to ensure proper functioning of the national (retail) energy markets.

No additional impact on public administration is expected from facilitating incentive based demand response as it is just a further specification/guidance on what is already an obligation under EED.

e. Trade-offs and synergies associated with each option with other foreseen measures

Promoting a wider-scale deployment of smart metering with fit-for-purpose functionalities is in line with the Commission's policy objectives namely to put the consumer at the core of the EU's energy system, given that:

- interoperable smart metering systems, equipped with the right functionalities, and connectivity to support novel energy services, are considered essential under the

Energy Union Strategy for bringing tangible benefits to consumers and delivering the "new deal";

- through smart metering, consumers can clearly experience the internal energy market working for them based on their preferences/choices, as it:
    - enables them to get accurate and frequent feedback on their energy consumption;
    - minimize errors and delays in invoices or in switching;
    - maximize their benefits from innovative solutions for consumption optimization (e.g. via demand response) and from emerging technologies (such as home automation); and ,
- reduce the costs of the operation and maintenance of energy distribution infrastructure (ultimately born by consumers through distribution tariffs).

Mandating the minimum functionalities for smart metering will clarify the need to go beyond the capability of delivering just 'actual time of use' information currently mentioned in the related provisions of the Energy Efficiency Directive.

Furthermore, the proposed smart metering functionality to collect meter data at intervals at least equal to the market settlement frequency will support trading and the harmonisation of balancing markets.

In addition to bringing tangible benefits to consumers, further developing demand response is fully coherent with the objectives of other priorities in the field of energy policy as an appropriate market framework for demand response:

- is an enabler for integrating renewables efficiently into the electricity system. It also contributes to render energy storage and self-consumption viable;
- is a key factor for increasing energy efficiency with savings of final but mainly primary energy;
- is a key factor in promoting new products in balancing markets where new rules are being elaborated under the Market Design Initiative to increase competition;
- may help to reduce the need for creating capacity markets and will therefore be considered under the rules for capacity markets to be proposed under the Market Design Initiative;
- will be needed to make efficient use of existing networks and thereby is at the core of the proposal concerning new distribution tariff rules;
- will likely trigger the deployment of smart homes and smart buildings technologies while these will *vice-versa* increase the interest of residential and commercial consumers in participating in demand response programmes. This deployment is foreseen to be supported by measures to be adopted under the Ecodesign/Energy Labelling Framework and by new approaches for smart buildings to be proposed in the context of the review of the EPBD in 2016.

f. Uncertainty in the key findings and conclusions and how these might affect the choice of the preferred option

The analysis on smart metering systems and especially demand response contains a lot of uncertainty. For smart metering systems detailed national cost-benefit analyses have been carried out in 2012. However, the underlying assumptions especially with regard to technology costs that are significantly decreasing may change over time. Also the potential benefits in terms of system and consumer benefits are subject to change depending on technology development, the further integration of decentralised renewable energy generation and upcoming offers for consumers taking part in demand response schemes. Considering the above it is not unlikely that currently the costs for smart metering are over- and the benefits under-estimated in some national cost-benefit analyses.

For incentive based demand response the uncertainty is even greater. Relatively good estimates can be made about the theoretical potential of demand response (see chapter 2 of this annex) where most of the theoretical potential lies with the residential sector. However, the technical and economic potential in the residential sector depends on a number of external factors that are hard to quantify:

- The willingness for residential consumers to engage in demand response. Pilot projects have proven that consumers do engage in the market and adjust their consumption if the incentives are right. These incentives are not always monetary but can also be related to access to advanced information or energy managing tools. However, it is impossible to transfer the results of pilots with engaged consumers to the broad majority of consumers;
- The uptake of heat pumps and electric vehicles that provide considerable shift-able load will most probably determine if a huge number of residential consumers will engage in demand response schemes. However, the uptake of those technologies is yet uncertain;
- Experiences from the Nordic market are not easily transferable to all EU markets as the shifting potential in Finland is relatively high due to e.g. electric heating;
- Experiences from the US market are equally not easily transferable to Europe as the US market design is different. Furthermore wholesale peak prices are higher and more frequent than in Europe. Hence, the economic value of demand response in the US is higher than in the Europe.

The above indicates that the amount of the monetary benefits under the different options is rather uncertain. The figures therefore rather indicate the magnitude of the potential benefits under the different options.

As outlined earlier in this chapter there is also great uncertainty about the results calculated for Option 3 in this impact assessment:

- The analysis only covered the EU as a whole and did not look into national impacts of a mandatory roll-out. It equally assumes the same cost of smart meters and their roll-out across the EU. Therefore it cannot be excluded that in some Member States the costs of a mandatory roll-out of smart meters exceeds its benefits as it was concluded in some national cost-benefit assessments;
- The analysis also did not quantify the potential system impact if independent aggregators are exempted from financially covering the distortions they induce to the system, e.g. not having any balancing responsibilities.

Therefore, the results of Option 3 are even more uncertain than under the other Options and may very well lead to additional system costs and in some Member States to costs for smart metering systems that are not covered by benefits for the system and/or the consumer.

The uncertainty about the uptake of demand response does, however, not affect the assessment of the preferred option. This option (Option 2) does not foresee any enforced measures on the roll-out of smart meters or on the uptake of demand response. Instead, all measures foreseen under this option are just enabling consumers to have access to the right technologies and access to third party service providers. They also foresee to improve access of flexibility to the markets. Under those framework conditions it will be the market that will show to which degree demand response can play a role as a competitive service. Therefore, Option 2 can be considered as a no regret option.

g. Preferred Option

Flexibility is considered to be instrumental for allowing more renewables into the European electricity system without having to make large investments in conventional back-up generation capacity. Therefore, introducing flexibility to the energy system by accelerating the uptake smart metering systems and of demand response are key elements for realising the Energy Union's objectives.

All three Options are fully coherent with the objectives of the Energy Union and other EU policies. The analysis has proven that all options are suited to accelerate the uptake of smart metering systems and demand response as well as this uptake will lead to significant system benefits and cost savings.

Option 1 supports the objective of increasing efficiency of the energy system by introducing smart meters and dynamic pricing contracts. The Third Package included the promotion of smart meters by requesting Member States to undertake a CBA of smart meters and where the benefit-cost ratio is positive to roll-out smart meters. The realisation of Option 1 means also in Member States where there is no general roll-out, relevant consumers can ask for the smart meter and a dynamic price contract. It hence provides the framework to allow all consumers to take advantage of the technological developments. However, while better enabling price based demand is crucial for incentivising residential consumers to benefit, it is not suited to realise the full benefits demand response can offer. As such realising Option 1 will only lead to increase total demand response in Europe by approximately 7% and lead to net benefits of approximately 120 MEUR/y by 2030 (compared to BAU).

In addition to the measures proposed under Option 1, **Option 2** is specifically addressing incentive-based demand response. Article 15 of the Energy Efficiency Directive already promotes demand flexibility and in that respect includes requirements for promotion of demand response. The additional measures in Option 2 are based on the assessment that in most Member States a complete legal framework for demand response is still missing. The measures in Option 2 aim at providing this framework by creating fair market access for independent aggregators and allow flexibility to be traded in organised markets. The analysis has shown that those measures are indeed suited to increase the uptake of demand response by approximately 52% which leads to system benefits of approximately 1230 MEUR/y by 2030 (compared to BAU).

Box X: Benefits and risks of dynamic electricity pricing contracts

The preferred option (Option 2) is to provide all consumers the possibility to voluntarily choose to sign up to a dynamic electricity price contract and to participate in demand response schemes. All consumers will have equally the right to keep their traditional electricity price contract.

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

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

Under **Option 3** a mandatory roll-out of smart meters to at least 80% of consumers in all Member States is included. In addition it is assumed that under this option aggregators do not have to cover the costs they induce to the system and hence do not pay any compensation to BRPs. In terms of uptake of demand response (more than 100% compared to BAU) and overall system benefits (1430 MEUR/y by 2030) this is the most favourable option. However, there are also other impacts that need to be considered in this respect:

- This analysis did not take into account national differences in the costs/benefits of smart meter roll-out but instead average figures were used. This approach does hence not exclude the possibility that the overall economic impact of a mandatory smart meter roll can be negative in some Member States as already suggested in national cost-benefit analyses;
- The exclusion of any compensation mechanism introduces a possibility of demand aggregators being free riders in the markets and therefore creating inefficiencies. This is not in line with the EU target model and generally not in line with creating a level playing field for competition.

Option 2 is considered to be the preferred option, considering that

- the modelling used for this Impact Assessment did not account for national differences and did not calculate the impacts per Member State;
- national cost-benefit analyses suggests that in some Member States mandatory roll-out of smart meters yields negative net benefits; and that,
- the overall banning of any financial obligations by independent aggregators may lead to market distortions with unknown overall impacts.

3.1.6. *Subsidiarity*

The options envisage to give consumers the right to a smart meter with all functionalities and access to dynamic electricity pricing contracts (Option 1) and in addition further specify the roles and responsibilities of third parties offering demand response services (Option 2). These actions promote the interests of consumers and ensure a high level of consumer protection, and have their legal basis in Article 114 of the Treaty and Article 194 (2) TFEU. The policy measures considered under Option 3 can be based on the same provisions.

Option1

- The principle of subsidiarity is respected and EU action is justified as access to smart metering systems is fundamental to improving the functioning of the internal electricity market;
- Ensuring universal consumer rights in the EU electricity markets includes the right to actively engage in the market. This is only possible if technologies enabling innovative energy services are available to all consumers across all Member States.

As stated earlier, for consumers to directly react to price signals on electricity markets, and enjoy benefits coming from the provision of new energy services and products, they must have access to both a fit-for-purpose smart metering system as well as an electricity supply contract with dynamic prices linked to the spot market. However, today this is only a reality in the Nordic Member States and Spain. In addition, under current national smart metering rollout plans till 2020, more than 30% of EU consumers could be excluded from access to such metering systems. The Commission's objective is to ensure that consumers have access to all the prerequisites necessary to be rewarded for reacting to market signals.

This cannot be achieved sufficiently by Member States acting along. Therefore, it is herein proposed to table provisions that will give each consumer, throughout the EU, the right to request the installation of, or the upgrade to, a smart meter with all 10 functionalities proposed in the Commission Recommendation on preparations for the roll-out of smart metering systems[115], while ensuring that consumers fairly contribute to associated costs. Furthermore, it needs to be ensured that every consumer has the choice to select a dynamic price contract linked to the prices at the spot market.

Action at EU level is relevant given that the current EU provisions, which leave the roll-out of smart metering to the Member States' discretion based on the results of their cost-benefit analysis, led to a fragmented, and even not necessarily functionally suitable in all cases, deployment of smart metering.

Actions by Member States alone cannot ensure a harmonised level of consumer rights (right to a smart meter that would enable customers access certain energy services) to the extent to which under current national smart meter rollout plans for 2020, more than 30% of EU consumers could be excluded from access to such metering systems. The right to a smart meter with all the ten recommended functionalities is a precondition for consumers to access energy services[116] that require accurate and frequent billing information such as demand response or electricity supply contract with dynamic prices linked to the spot market.

The costs of rolling out smart meters - with all the benefits that this can bring for consumers, network and energy companies, the energy system as well as society and the environment more widely - will greatly increase if the economies of scale of the EU's internal market are not properly leveraged. Regional differences have already risen with respect to functionality and interoperability of the systems being rolled out, which may result in set-ups that are not necessarily interoperable at national level, or within the EU. This adds complexity and costs to those, be it for instance energy services/product developers or aggregators, who would like to trade in different European countries and optimise their business model. It points to the need to harmonise to a certain extent system requirements and functionalities of smart electricity meters.

In the context of completing the EU's internal electricity market and making retail work also for consumers, it is highly relevant to ensure at EU level a degree of consistency and alignment, as well as gain momentum, in the deployment and use of smart metering throughout Europe. Furthermore, ability to access novel energy services and products

[115] For example, provide readings directly to the customer and any third party designated by the consumer, include advance tariff structures, time-of-use prices and remote tariff control, provide secure data communications, etc. These also carry a host of other benefits such as improved consumer information, enabling self-generation to be rewarded, and delivering flexibility to the system.

[116] e.g. demand response, self-consumption, self-generation

should be indiscriminately offered to all EU citizens. This is what this action – giving the right to request the installation of, or the upgrade to, a smart meter - is meant to deliver.

Such an action will eliminate ambiguities and strengthen the existing provisions, in order to give certainty to those planning to invest, and ensure that smart metering roll-outs move in the right direction, and regain EU added-value, by namely (i) safeguarding common functionality and sharing best practices; (ii)ensuring coherence, interoperability, synergies, and economies of scale, boosting competitiveness of European industry (both in manufacturing and in energy services and product provision), and (iii) ultimately delivering the right conditions for the internal market benefits to reach also consumers across the EU.

Option 2

EU intervention can be justified for several reasons, among them are:

- To improve the proper functioning of the internal market and avoid the distortion of competition in the field of retail energy services and hence fully enable demand response
- To empower consumers by enabling them to take advantage of the well-functioning retail energy markets by easily accessing demand response services under transparent and fair conditions.

Divergent national approaches related to the development of demand response services, or the lack thereof, led to different national regulatory frameworks, raising barriers to entry across borders to demand response aggregators. This initiative complies with the principle of subsidiarity, as Member States on their own initiative would not be able to remove the barriers that exist between national legislations to independent demand response service-providers and to create a level playing field for them.

Each Member State individually would not be able to ensure the overall coherence of its legislation with other Member States' legislations. This is why an initiative at EU level is necessary. It will reduce costs for businesses as they will no longer have to face different national regimes. It will create legal certainty for businesses which want to provide demand response services in other Member States. Common rules are also crucial when e.g. balancing markets will be opened for cross-border trade of flexibility.

Moreover, the present initiative will add value to other measures in the Market Design Initiative. Other measures aimed at empowering customers, such as right to a smart meter and to a dynamic ricing contract, will create new opportunities for European consumers and energy service companies. These opportunities can only be exploited to their maximum extent if they are completed by an initiative on addressing market barriers to aggregators, so that they are able to provide customers with access to demand response services.

Action from Member States alone is likely to result in different sets of rules, which may undermine or create new obstacles to the proper functioning of the internal market and create unequal levels of consumer rights in the EU. For example, a framework for demand response for households is currently being developed in France, while in other Member States there are currently no established rules for demand response aggregators targeting household consumers. Common standards at EU level are therefore necessary to promote efficient and competitive conditions in the retail energy sector for the benefit of EU consumers and businesses.

An initiative at EU level would ensure that consumers in all Member States would benefit from demand response services under harmonised conditions. It would also help removing entry barriers for new service providers (aggregators), including cross-border, therefore stimulating economies of scale and setting the basis for developing flexibility markets at regional level. Such services have a cross-border development potential (e. g. Energy Pool is already active in more than one EU Member States – France, UK).

Option 3

The same arguments to justify EU action as for Option 1 and 2 can be used for the policy measures under Option 3. However, what concerns smart metering there could be doubts that a mandatory roll-out of smart meters with all recommended 10 functionalities conforms to the principles of subsidiarity and proportionality. This is especially relevant as Member States have already conducted national cost-benefit analyses on smart meter roll-out. In 11 Member States those CBAs have unveiled that under current conditions the costs of a roll-out exceed the benefits. In the Commission's analyses no evidence has been found that those national CBAs or their underlying assumptions could be contested or that economies of scale realised by a European roll-out would render the roll-out economically viable. Hence, a mandatory roll-out would effectively impose undue costs on those Member States where the CBAs have been negative. However, the underlying assumptions of those CBAs are likely to change over time with technology cost expected to decrease which may lead to viable roll-outs in the near future.

The principle of proportionality may equally be contested for strict harmonisation of the legislative framework for independent aggregators and demand response. A certain degree of freedom for Member States to design the framework for demand response according to the national design of the markets may indeed have a similar impact than fully harmonised rules.

3.1.7. *Stakeholders' opinions*

Outcome of the public consultation

Result of public consultation Energy Market Design

The consultation on the market design contained one question on demand response:

> *"Where do you see the main obstacles that should be tackled to kick-start demand response (e.g. insufficient flexible prices, (regulatory) barriers for aggregators / customers, lack of access to smart home technologies, no obligation to offer the possibility for end customers to participate in the balancing market through a demand response scheme, etc.)?"*

Many stakeholders identified a lack of dynamic pricing (more flexible consumer prices, reflecting the actual supply and demand of electricity) as one of the main obstacles to kick-starting demand side response, along with the distortion of retail prices by taxes/levies and price regulation. Other factors include market rules that discriminate consumers or aggregators who want to offer demand response, network tariff structures that are not adapted to demand response and the slow roll-out of smart metering. Some stakeholders underline that demand response should be purely market driven, where the potential is greater for industrial customers than for residential customers. Many replies point at specific regulatory barriers to demand response, primarily with regards to the lack of a standardised and harmonised framework for demand response (e.g. operation and settlement). [117]

In total, eleven Member States responded to the question with ten putting specific emphasis on the need for effective price signals that reflect price developments at the wholesale market and incentivise consumers to adjust their consumption. In addition, seven Member States highlighted the need for market rules that allow demand response to participate in wholesale, balancing and capacity markets on equal footing with generation. Also environmental NGOs have been widely supportive of demand response stressing the need for demand side measures to efficiently integrate renewables to the system. Therefore, they call for opening the markets for flexibility. Some organisations call for intensified R&D in the area and/or support schemes while one organisation also calls for targets for demand response. However, Member States and other stakeholders see demand response as a market driven service for which no specific support but fair market conditions is needed. More detail on the opinion of main stakeholders is presented under the individual stakeholder organisations.

[117] IEA "*Re-powering markets*" (2016) suggests*: Reform of retail pricing is urgently needed to better reflect the underlying cost level and structure. Current tariff and taxation structures which do not vary with time can lead to inefficiencies. Investments in distributed resources are not always cost-effective as bill savings do not properly reflect the avoided costs to the electricity system. The significant difference in speed between installing solar PV and small-scale storage and building large-scale power infrastructure can exacerbate this problem*."

Result on public consultation on the Review of Directive 2012/27/EU on Energy Efficiency

The consultation addressed a number of questions on metering with one specifically addressing electricity smart meters and hence is immediately relevant to this impact assessment:

"Do you think that

- *the EED requirements regarding smart metering systems for electricity and natural gas and consumption feedback and*
- *the common minimum functionalities, for example to provide readings directly to the customer or to update readings frequently, recommended by the Commission together provide a sufficient level of harmonisation at EU level? "*

37% shared the view that the EED requirements regarding smart metering systems for electricity and natural gas and consumption feedback and that the common minimum functionalities recommended by the Commission together provide a sufficient level of harmonisation at EU level. 36% had no view, and 27% did not think that these provisions would provide a sufficient level of harmonisation.

Several participants explained that smart meters would have to provide more useful information to consumers, potentially in 15 minute intervals, or even in real time. Some also suggested that consumers could receive a notification once every three months with an overview on whether they are saving energy and hence money, or whether they are consuming more than would be expected. Yet others noted that the above factors largely depend on market conditions, and on how providers interact with customers. In general, many participants shared the view that EU standards should only apply to minimum ones, as any additional standards could significantly increase the enterprise's complexity. Additionally, several stated that harmonisation must also take into account acceptance by citizens. Finally, some also cited evidence that calls the effectiveness of smart meters in general into question.

Of those 27% who think that the EED requirements regarding smart metering systems for electricity and natural gas and consumption feedback and the common minimum functionalities, recommended by the Commission together do not provide a sufficient level of harmonisation at EU level, 48% share the view that common minimum functionalities should be the basis for further harmonisation. 31% had no view, and 21% did not thing that common minimum functionalities should be the basis for further harmonisation. Some called for additional minimum functional standards to the current ones, for example, monthly or three monthly electronic feedback for consumers on how much energy they are savings. Some participants also argued that the interface of smart meters should be standardised, to facilitate their use. Yet others voiced a shared perception that standards across the EU would be overly determined by utilities.

More detail on the opinion of main stakeholders is presented under the individual stakeholder organisations. While among all respondents the views on the need of additional EU actions was balanced, the opinion of national ministries signal that the majority of Member States believe that the existing provisions are sufficient. Out of 14 replies from Member States only 2 were of the opinion that more harmonisation on EU level would be good to ensure that consumers get the full benefit out of smart meters while 9 consider that the level of harmonisation provided by existing legislation is sufficient and 3 do not state a clear opinion.

European Institutions

Council of the European Union, messages from the presidency on electricity market design and regional cooperation, April 28, 2016, 7876/1/16 REV1

In addition to stakeholders also European Institutions in response to the communications *"Launching the public consultation process on new energy market design"* (SWD(2015) 142 final) as well as *"Delivering a new deal for consumers"* (SWD(2015) 141 final) clearly highlighting the need for smart metering systems, demand response and the importance of allowing new market participants (aggregators) to compete in the markets.

European Parliament, Committee on Industry, Research and Energy, Rapporteur: Werner Langen, DRAFT REPORT on 'Towards a New Energy Market Design', 27.1.2016, 2015/2322(INI)

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

European Parliament, Committee on Industry, Research and Energy, Rapporteur: Theresa Griffin, REPORT on delivering a new deal for energy consumers, 28.4.2016, A8-0161/2016

- *"5. Recalls that the ultimate goal should be an economy based on 100% renewables, which can only be achieved through reducing our energy consumption, making full use of the 'energy efficiency first / first fuel' principle and* ***prioritising energy savings and demand side measures over the supply side*** *in order to meet our climate goals…"*
- *"6.b empower citizens to produce, consume, store or trade their own renewable energy either individually or collectively, to take energy-saving measures, to become active participants in the energy market through consumer choice,* ***and to allow them the possibility of safely and confidently participating in demand response;****"*
- *"33. Stresses that to incentivise demand response, energy prices must vary between peak and off-peak periods, and therefore* ***supports the development of dynamic pricing on an opt-in basis****, subject to a thorough assessment of its impacts on all consumers; stresses the need to* ***deploy technologies that give price signals which reward flexible consumption****, thus making consumers more responsive; ... reminds the Commission that when drafting the upcoming legislative proposals it should be guaranteed that the introduction of dynamic pricing is matched by increased information to consumers;*
- ***"37. Emphasises that consumers should have a free choice of aggregators and energy service companies (ESCOs) independent from suppliers";***

Committee of the Regions, Opinion of the European Committee of the Regions – Delivering a New Deal for Energy Consumers, 8 April 2016, ENVE VI -/009

- *"3. notes the extremely high number of services and technical solutions that exist or are currently being developed in the fields of management and demand response, as well as in the management of decentralised production. The European Union must ensure that priority is given to encouraging and supporting the development of these tools, assessing their value and impact, whether economic, social, environmental or in terms of energy, and monitoring their usage to make sure that energy is safe, easy and affordable"*;
- *"24. observes that a level playing field should be created for all future players who generate and supply energy and/or provide new services, in order to enable, for example, grid flexibility and integration of energy produced by "prosumers" (including aggregators)"*;
- *"42. reiterates its call to speed-up the development of smart systems at both grid and producer/consumer level, to optimise the system as a whole, as well as to* ***introduce smart meters, which are essential to the efficient management of demand with the active involvement of the consumer"****;*
- *"43. calls for the adoption of a strict framework at European level on the deployment of* ***smart meters and their range of uses and features****, whilst recalling that the aim is to streamline and reduce consumption. In this regard, the Committee calls for all new technology options to be evaluated prior to adoption, if they are to be introduced as standard, with regard to their potential energy, economic, social and environmental impact";*

Selected Stakeholder's views

Florence Forum of electricity regulation – Conclusions of 31 meeting on June 13, 2016

The Forum recognises that the development of a holistic EU framework is key to unlocking the potential of demand response and to enabling it to provide flexibility to the system. It notes the large convergence of views among stakeholders on how to approach the regulation of demand response, including:

- The need to engage consumers;
- The need to remove existing barriers to market access, including to third party aggregators;
- The need to make available dynamic market-based pricing;
- The importance of both implicit and explicit demand response; and,
- The need to put in place the required technology.

Regulators (ACER/CEER)

The Agency for the Cooperation of Energy Regulators (ACER) and the Council of the European Energy Regulators (CEER) both welcomed the Commission's energy market design consultation paper of July 2015, and in particular the reinforced steer towards cross-border and market-based solutions, and noted its *"**alignment in thinking**"* with their *Bridge to 2025* proposals and sharing of *"the common aim of **establishing liquid, competitive and integrated energy markets that work for consumers**"*[118].

They consider that *"**a well-functioning market is characterised by innovation and a range of products offered to consumers**"*, which *"can be a sign of healthy competition and innovation in the market"*. Key features of this new consumer-centric energy market model advocated by the regulators[119] rely on *"**near real time frequency of smart metering data for all**"*, and *"**demand response through flexible consumption**"*. The latter translates into "*availability of time-of-use/hourly metering and different pricing schemes offers from suppliers and availability of aggregation services from third-party companies*". To assist realising this, CEER amongst other works towards ensuring that "*most customers have a minimum knowledge of the most relevant features for engaging and trusting the market*", access to *"empowerment tools"* and *"a minimum level of engagement"*, as well as that the *"regulatory framework allows and incentivises the availability of a range of offers"*[120].

CEER when discussing[121] **implicit, or price-based demand response**, it states that *"without smart meters (and optionally in addition other facilitators such as smart appliances)"* and in the absence of **dynamic pricing contracts**, there are *"limited possibilities for retailers to value demand side flexibility in their portfolio optimisation"*. CEER further notes that "*access to contracts that directly link the energy component to wholesale markets with a possible granularity down to hourly-based prices create a bridge between wholesale and retail markets, incentivising consumers to exploit opportunities when prices are low and to adjust consumption when prices are high*".

Furthermore, CEER affirms that *"the **availability of smart metering equipment and systems** which allow time-of-use meter readings **is a pre-requisite for consumers** to be able **to opt into implicit demand response** schemes. Smart meters may also enable explicit demand response services through a dedicated standard interface, either as mandatory equipment or an option"*[122]. But for smart meters to be able to deliver this service, they need to be fit-for-purpose, and therefore equipped with the right functionalities. CEER notes that *"there is a **consistency and convergence** between the work of European Energy Regulators and the European Commission regarding smart*

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118 ACER/CEER common press release *"Energy Regulators (ACER/CEER) welcome the market-based solutions and cross-border focus of the European Commission's energy market design*", 15.07.2015; http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/PRESS_RELEASES/2015/PR-15-07_Joint-CEER-ACER%20PR%20%20-EnergyMarketDesignConsultation_FINAL.pdf

119 CEER presentation at the 12th EU-US Roundtable, 03.05.2016; http://www.ceer.eu/portal/page/portal/EER_HOME/EER_INTERNATIONAL/EU-US%20Roundtable/12th_EU-US_Roundtable/12th%20EU-US%20RT_S4-International_deSuzzoni.pdf

120 idem

121 CEER discussion paper *"Scoping of flexible response"*, 3 May 2016; http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2016/C16-FTF-08-04_Scoping_FR-Discussion_paper_3-May-2016.pdf

122 CEER *"Position paper on well-functioning retail energy markets"*, , 14 October 2015; http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab5/C15-SC-36-03_V19_Well-functioning_retail_markets.pdf

meter functionalities, in particular those which benefit consumers". At the same time, however, CEER does not consider these elements sufficient for providing the necessary level of harmonisation across the EU, *"the issue being that Member States do not apply them"*. *Consequently, CEER are* ***in favour of using the "minimum functionalities as a basis for further harmonisation"***[123].

TSOs (ENTSO-E)

ENTSO-E considers that *"the development of demand-side response (DSR) should ensure that* ***demand elasticity is adequately reflected in short-term price building and long-term investment incentives****. DSR can deliver different types of products and participate in the associated markets with large socio-economic welfare gains*"[124]. Furthermore, ENTSO-E notes that *"the organisation of, and timely access to, metering and settlement data which will be made available by smart meters is essential for facilitating the uptake of DSR"*[125]. Elaborating on that, ENTSO-E states that the full potential can be unleashed if the following requirements[126] are satisfied, namely:

(i)*"****price signals*** *need to reveal the value of flexibility"* for the electricity system;

(ii)"*efficient use of DSR is based on an economic choice between the value of consumption and the market value of electricity. This choice arises when the* ***consumer is exposed to variable prices or*** *if the consumer* ***can sell his flexibility on the market****, possibly with the help of an aggregator*".

(iii) *"****access to price information, consumption awareness*** *and DSR activation require strong consumer involvement, which can be facilitated with* ***automation*** *or by delegating the DSR process from the consumer to a company"*;

(iv) *"****regulatory barriers****, when present,* ***need to be removed*** *to unlock full DSR potential, including barriers related to the* ***relationship between independent aggregators and suppliers****. Any evolution must preserve the efficiency and well-functioning of markets and their design components, such as the pivotal role of balance responsible parties, their information needs and balancing incentives. From a TSO perspective, the choice of the market model results from a* ***trade-off between the imperatives not to increase residual system imbalance and to facilitate the development of additional resources"***;

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123 CEER Response to European Commission Public Consultation on the Review of the Energy Efficiency Directive, 29 January 2016; http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab6/C16-CRM-96-04_EC_PC_EED_Response_290116.pdf

124 ENTSO-E policy paper "*Market design for demand response*", November 2015; https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/entsoe_pp_dsr_web.pdf

125 ENTSO-E position paper "*Towards smarter grids: Developing TSO and DSO roles and interactions for the benefit of consumers*", March 2015; https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/150303_ENTSO-E_Position_Paper_TSO-DSO_interaction.pdf

126 ENTSO-E policy paper "*Market design for demand response*", November 2015; https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/entsoe_pp_dsr_web.pdf

(v)"***DSR should develop itself based on viable business cases.*** *Subsidies should remain limited and clearly identified*";

(vi)"***Communication and control technologies*** *need to enable DSR for small consumers and provide guarantees on their reliability*"**.**

ENTSO-E also clarifies that *"to enable dynamic pricing, settlements must be based on at least hourly metering values"*, which means that *"Member States must phase out static consumption profiles, and introduce time-of-stamped (at least hourly) smart meter readings for consumers*"[127].

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[128] *"with the growing uptake of smart grids and distributed energy connected to Europe's distribution grids, DSOs are successfully embracing the 'digitalisation' transformation"*, and are **in favour of *"the procurement of flexibility services in an open market context*** *where everyone, including end users, is welcome to take part."* They have also affirmed in different fora their conviction on the key role that smart metering plays in delivering that function and the accompanying benefits, by providing accurate and secure data on energy consumption, while enabling customers to make smart choices helping them to also save money and energy.

CEDEC

CEDEC considers that[129] *"in order to implement effective demand-response programmes, signals about demand and supply need to be received, managed and communicated to the relevant parties. For this, the development of smart distribution grids is indispensable"*. Moreover, *"for the development of smart grids, cost-reflective regulatory frameworks need to be in place… " giving the right incentives, that should amongst others, "allow for time-differentiated prices, which will* ***give price signals to consumers to shift their consumption*** *from peak to off-peak times*"[130]. Such settings are more complex and in fact *"**only possible with a smart meter***"[131].

[127] ENTSO-E *"Recommendations to the regulatory framework on retail and wholesale markets";* Input to EC Market Design Package; 10 June 2016.

[128] DSOs Associations' joint event *"Innovative DSOs are needed in a Decentralised Energy System"*, 12.04.2016, http://www.geode-eu.org/uploads/GEODE%20Germany/Stellungnahme/2016/0411%20FINAL%20Joint%20PR%20-%20Innovative%20DSOs%20in%20a%20decentralised%20energy%20system.pdf

[129] CEDEC position " *on EC Communication - Delivering the internal electricity market and making the most of public Intervention*", December 2013; http://www.cedec.com/files/default/cedec-position-ec-guidance-package-final.pdf

[130] CEDEC publication "*Smart grids for smart markets*", 2014; http://www.cedec.com/files/default/cedec_smart_grids_position_paper-2.pdf

[131] CEDEC publication "*Distribution grid tariff structures for smart grids and smart markets*", 2014; http://www.cedec.com/files/default/cedec%20leaflet%20grid%20tariffs-final-140403-1.pdf

EDSO for Smart Grids

EDSO considers that DSOs are at the core of the energy transformation and have *"the **potential to empower consumers** to take a more active part in the energy system, for example, **by rolling-out smart meters**"*[132]. Furthermore, EDSO argues that *"engaging consumers will require appropriate incentives and technologies"*, as well as *"clear price signals", for flexibility markets to develop and demand response to deliver its full benefits"*[133]. EDSO notes that incentives for *"**dynamic tariffs or incentive based demand response**"* should be set up *"in order for the consumer to make savings by offering controllable loads to network operators"*. It also advocates that a *"revision of grid tariffs with time-dependent and site-dependent components or incentive based demand response, is an essential step towards realising the benefits, as well as for passing on the costs of flexibility*"[134].

Furthermore, EDSO states that *"DSOs could make the most of their grid provided that they are allowed to use system flexibility services*"[135]. Moreover, *"**increasing flexibility** in the electricity market (when technically and economically appropriate) would result in a number of benefits for DSOs, consumers (all grid users) and society as a whole*". However, according to EDSO *"this implies that **distribution networks are planned differently**, incorporating new risk margins and uncertainty, are not only managed as they used to be, but rather as networks with enhanced observability, controllability and interactions with market stakeholders"*.

Regarding smart metering functionalities, EDSO claims[136] that the ***"EED requirements and the EC recommendation" on common minimum functionalities*** "have been **useful in assisting the industry identify the most relevant functionalities for smart meters**. *Now that most national deployments are underway or near launch,* ***there is no need for further action from the European Commission***". Furthermore, it notes that *"proposing to further harmonise smart meter systems at this time, beyond the existing EC's recommendations on minimum smart metering functionalities, could further delay smart meter deployment and thus consumers' access to detailed and accurate information on their energy consumption"*.

EURELECTRIC

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132 EDSO report "*Data Management: The role of Distribution System Operators in managing data*", June 2014; http://www.edsoforsmartgrids.eu/wp-content/uploads/public/EDSO-views-on-Data-Management-June-2014.pdf

133 EDSO report "*Flexibility: The role of DSOs in tomorrow's electricity market*", May 2014; http://www.edsoforsmartgrids.eu/wp-content/uploads/public/EDSO-views-on-Flexibility-FINAL-May-5th-2014.pdf

134 idem

135 System flexibility services: any service delivered by a market party and procured by DSOs in order to maximise the security of supply and the quality of service in the most efficient way – Reference: EDSO report " *Flexibility: The role of DSOs in tomorrow's electricity market*", May 2014.

136 EDSO response to the Consultation on the Review of Energy Efficiency Directive, January 2016; http://www.edsoforsmartgrids.eu/wp-content/uploads/160129_Public-consultation-Energy-Efficiency-Review_final_EDSO.pdf

Eurelectric acknowledges that *"demand response will be one of the building blocks of future wholesale and retail markets*", and *"the development of innovative demand response services will empower customers, giving them more choice and more control over their electricity consumption. Phasing out regulated retail prices and* ***rolling out smart meters*** *continue to be* ***key prerequisites*** *to advance demand response further*"[137]. As Eurelectric explains[138] it is *"**fit-for-purpose smart meters**" that are needed and are "... a key tool to empower consumers*". And *"...without prejudice to smart meter rollouts which are already ongoing, it would be* ***important to guarantee that all smart meters across the EU had a minimum agreed common set of functionalities*** *to make sure that they contribute to consumer empowerment and efficient retail markets. Basic common functionalities would include, for example, the possibility of performing remote operations, the capability to* ***provide actual, close to real-time meter readings to consumers****, or the possibility to* ***support advanced tariff schemes****"*[139]. Furthermore, Eurelectric supports the position that *"**smart meters with a reading interval corresponding to the settlement time period are a technical prerequisite** for participation of users (with aggregated flexibility units) in balancing markets*"[140].

To untap the full demand response potential, Eurelectric recommends[141]:

(i) "***ensuring*** *that the* ***demand response value is market-based*** *in order to avoid any extra costs to the system, customers and other actors*";

(ii) *"implementing* ***adequate communication*** *between third party aggregators and balance Responsible Parties (BRPs)/suppliers to ensure that demand response can take place effectively";*

(iii) *"ensuring that BRPs/suppliers are compensated for the energy they inject and that is re-routed by third party aggregators*", and *"to this end, third party demand response aggregators and suppliers agree on the* ***rules of compensation****. Changes in market rules and settlement adjustments could also be implemented. In addition, a* ***clear balance responsibility of third party aggregators*** *is needed*";

(iv) *"ensuring that, on a commercial basis, BRPs/suppliers are able to* ***renegotiate supply contracts*** *to take into account the indirect effects of demand response (e.g.* ***rebound effects****) and consequent impacts on sourcing costs*"; and

137 Eurelectric report "*Designing fair and equitable market rules for demand response aggregation*", March 2015; http://www.eurelectric.org/media/169872/0310_missing_links_paper_final_ml-2015-030-0155-01-e.pdf

138 Eurelectric report "*The power sector goes digital - Next generation data management for energy consumers*", May 2016; http://www.eurelectric.org/media/278067/joint_retail_dso_data_report_final_11may_as-2016-030-0258-01-e.pdf

139 idem

140 Eurelectric report "*Flexibility and Aggregation – requirements for their interaction in the market*", January 2014; http://www.eurelectric.org/media/115877/tf_bal-agr_report_final_je_as-2014-030-0026-01-e.pdf

141 Eurelectric report "*Designing fair and equitable market rules for demand response aggregation*", March 2015; http://www.eurelectric.org/media/169872/0310_missing_links_paper_final_ml-2015-030-0155-01-e.pdf

(v) *"facilitating demand response aggregation at distribution network level through information exchange between DSOs, TSOs and aggregators, for example* ***using a system that reflects network availability***".

GEODE

The association for the local energy distributors GEODE identifies the non-wide deployment of smart metering as one of the main barriers for demand response taking off, stating that there is *"...* ***no demand response and actual consumption data without smart meters*** *- which are still being rolled-out in many Member States"*[142]. Furthermore, it argues that *"...demand side flexibility* ***aggregators should have access to balancing markets on a level playing field with other parties****"*, and that *"...the* ***end customer should participate*** [in demand response schemes] ***on a voluntary basis only****"*.

Moreover, even though GEODE recognises the need, as stated in different fora, to ensure that smart metering systems with the right functionalities are rolled out to support demand response, it cautions on the making a set of functionalities binding without at least foreseeing a transition period for implementation. Following a survey that the association undertook among its members on the use of the common minimum functionalities for smart metering systems recommended by the Commission, it acclaimed[143] that *"... in those countries where the roll-out has just started or is still in a planning phase, almost all requirements as recommended by the European Commission are implemented"*. However it continues, *"...if the European Commission is considering* ***making binding the recommendations on smart meter functionalities*** […] ***these should apply for the next generation of meters to be rolled-out****. At least, a* ***sufficient transitional period should be provided*** *which is as long as the expected lifetime of the smart metering systems already installed respectively smart metering systems which are going to be installed in the next years - tenders are currently running or the roll-outs have recently started with the objective to reach the 2020 target of 80%. Otherwise it would – once again - require huge investments to be made by DSOs for replacing existing meters."*

Suppliers (Eurelectric)

Suppliers state that *"while demand response has been and could continue to be deployed by suppliers without* ***smart metering*** *or connected appliances, these technologies* ***will***

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[142] GEODE Comments to the European Parliament Draft Report on "*Delivering a New Deal for Energy Consumers*", http://www.geode-eu.org/uploads/GEODE%20Germany/DOCUMENTS%202016/GEODE%20Final%20Comments%20-%20EP%20Draft%20Report%20New%20Deal.pdf

[143] GEODE Position paper sent to EC services, dated 20/04/2016, entitled: "GEODE Survey – to assess whether EC common minimum functional requirements for smart metering systems for electricity - EC Recommendation of 9 March 2012 on preparations for the roll-out of smart metering systems (2012/148/EU) are implemented by GEODE member companies"

facilitate more advanced dynamic pricing and new demand response services"[144]. They recognise the benefits that the advent of smart metering, smart devices and overall digitisation of the energy sector will bring in this respect, and how it will change their interaction with consumers taking into a new level *"changing their traditional business models, based on pure delivery of kilowatt-hours towards **becoming full service providers**"*[145]. Suppliers will *"have access to new data sources and tools to communicate with their customers and better understand their needs"*. Furthermore, they *"…will (also) be able to provide consumers with information on - and prediction of - their energy usage and consumption patterns, even breaking it down into **close to real-time information**…through extra devices"*, and enable the delivery to them of *"**more personalised offers and services** by market players"*. This includes the proposition of *"**innovative demand response or time of use tariffs** which **contribute to the efficient operation of the energy system whilst being financially attractive**, **transparent and guaranteeing a given level of comfort to consumers** through remote steering of connected appliances."*

At the same time, utilities consider that despite their experience in collecting and processing meter readings, *"dealing with more granular data generated by smart grids and meters will carry a higher level of complexity"*, while competition in shaping and trading novel energy products to consumers *"will intensify from all sides"*, including from new actors. Suppliers welcome the changes that are coming but recognise that they *"will have to proactively find their place in this new ecosystem"*.

Aggregators (SEDC)

The Smart Energy Demand Coalition (SEDC) advocates that demand-side resources can play a crucial role in making the transition to a decarbonised energy system efficient and affordable, and also involving in this empowered energy consumers. SEDC believes that *"**a precondition for consumer empowerment is giving them a choice**: citizens, commercial and industrial consumers should be able to opt for the energy services they prefer, the services they wish to sell, and the service provider they wish to work with. This **includes the choice to valorise the flexibility of their devices and processes on the market**, the choice to self-generate electricity, or the **choice for real-time electricity pricing** to adjust parts of their consumption – automated or not – to the variability on the market and save costs. It also includes the **choice to work with** their energy supplier as well as **an independent energy service provider** such as a demand response aggregator for different services"*[146]. For this to happen, SEDC recommends a set of *"coherent measures to remove barriers currently in place and implement a long-term vision for*

[144] Eurelectric brochure "*Everything you always wanted to know about Demand Response*", 2015; http://www.eurelectric.org/media/176935/demand-response-brochure-11-05-final-lr-2015-2501-0002-01-e.pdf

[145] Eurelectric report *"The power sector goes digital - Next generation data management for energy consumers"*, May 2016; http://www.eurelectric.org/media/278067/joint_retail_dso_data_report_final_11may_as-2016-030-0258-01-e.pdf

[146] Article by F. Thies SEDC Executive Director appearing under "*Guest Corner*" in EC DG ENER Newsletter of May 2016; https://ec.europa.eu/energy/en/energy_newsletter/newsletter-may-2016

consumer engagement"[147], and advises that *"**the potential of demand-side flexibility (is) adequately included in all European scenario calculations and planning for infrastructure developments**".*

Amongst its recommendations, SEDC lists the following:

(i) *"EU rules providing for access for demand-side flexibility to all energy markets (wholesale, balancing, ancillary services and capacity) on an equal footing with generation"*, and **enabling *"customers … to participate in all markets directly or through an aggregator"***;

(ii) *"**third party aggregators** should **access all markets without prior agreement of** the respective customer's **energy retailer/Balance Responsible Party**"*; and ***"market prices should reflect the real value of electricity at any moment"***;

(iii) ***"any customer should have the right to a smart meter and to choose hourly, and where applicable quarter-hourly, market pricing;** the retailer/BRP should be settled accordingly"*;

(iv) *"**Distribution System Operators should be encouraged to make use of smart demand-side flexibility solutions** offered by market parties for system operations purposes. **Incentive structures** should be revised to this end"…, "… **network tariffs** should support, rather than hamper the use of demand-side flexibility, and perverse incentives must be removed".*

Consumer Groups

BEUC – the European Consumer Association, advocates that as we are moving towards a consumer-centric energy market, we need to ensure that we address both old and new challenges – with the latter being new technologies (smart meters, connected devices, smart homes), friendly demand-side response and new business models and new market players. BEUC believes that *"**increased consumer engagement is an important factor for the future energy sector**. This **requires innovative ideas** to empower consumers **backed by an appropriate legal framework**"*. Also, *"new products and services **need to respond to consumers' demands rather than risk confusing them** further. Moreover, as new technologies*[148] *make it technically possible to process much more data than as is current practice in the energy sector, compliance with **data protection** rules and their enforcement must be ensured"*[149].

BEUC feels that these technologies *"in general **may offer a larger choice of products and services** as well as more information for consumers, **yet the benefits for consumers are not guaranteed**"*[150]. It clarifies its rationale by noting that *"although new*

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[147] SEDC position paper "*10 Recommendations for an Efficient European Power Market Design*", 2016; http://www.smartenergydemand.eu/wp-content/uploads/2016/02/SEDC-10-recommendations.pdf

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

[149] BEUC website - http://www.beuc.eu/press-media/news-events/energy-union-what-it-consumers

[150] BEUC position paper "*Building a consumer-centric energy union*", July 2015; http://www.beuc.eu/publications/beuc-x-2015-068_mst_building_a_consumer-centric_energy_union.pdf

*technologies such as smart meters may help those who consume large amounts of electricity ..., **smart meters should not be understood as a necessity to achieve energy savings**. Therefore, instead of pushing through this technology, **new services** (facilitated by new technologies) **or demand response programmes should be based on understanding market opportunities and consumer outcomes**. Consumers should also have the **right to opt out** and have their meter operated in dumb mode. A **voluntary and consumer-centred roll-out of smart meters rather than a mandatory one** may increase consumer participation and public support as it facilitates ownership, data protection, security and cost allocation issues. Moreover, where smart meters are rolled out, **minimum functionalities and interoperability are essential** to ensure consumers have easy access to the information they need to take informed decisions on their consumption, but this is only the starting point. Further work is needed to build trust and encourage consumer engagement. Consumers urgently need **clear commitments that the investments** to upgrade the infrastructure and the roll-out of smart meters **will deliver benefits to them as well as monitoring and enforcement of these commitments**"*. BEUC therefore calls for *"a solid legal and regulatory framework" "...in order to guarantee that the roll-out is cost efficient and that **costs and benefits are fairly shared among all stakeholders who benefit from the new technology**"*. At this point BEUC also notes that *" the benefits to DSOs from smart meters in regard to running, surveillance, repairing and planning the network is often undervalued when setting the share of costs covered by consumers via their bills"*.

Regarding demand response, and looking at what the near future can bring to households in terms of demand response, BEUC states that a *"smart demand response scheme"* that can be of interest to consumers should be *"transparent (simple and clear offers and contracts); voluntary; rewarding flexibility and not penalising in-flexibility", "focus(ed) on consumers' needs and experience"*[151]. In fact **to guarantee consumers can benefit from demand response**, BEUC sees that[152]

(i) *"**transparency and comparability** are key to the success of new dynamic tariffs"*;

(ii)it is important to assess *"the degree to which consumers will likely rely on **automation** to deliver the expected benefits and ... how (novel energy) services (could) accommodate **consumers' lifestyles**"*;

(iii)*"regulators should ensure consumers' flexibility is **properly rewarded** and that there are **price safeguards** when consumers are fully exposed to wholesale market developments"*; and

(iv) calls for the *"European Commission to coordinate with Member States and national regulators a distributional analysis on the **impact of time-of-use tariffs on different social groups** and if/how these groups can access the **benefits of new deals**"*.

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151 BEUC presentation at the EUSEW 2016 event "*Engaged customers driving the energy transition*", 16.06.2016 - http://eusew.eu/engaged-customers-driving-energy-transition

152 BEUC position paper "*Building a consumer-centric energy union*", July 2015; http://www.beuc.eu/publications/beuc-x-2015-068_mst_building_a_consumer-centric_energy_union.pdf

3.2. Distribution networks

3.2.1. *Summary table*

Objective: Enable Distribution System Operators ('DSOs') to locally manage challenges of energy transition in a cost-efficient and sustainable way, without distorting the market.		
Option: 0	Option 1	Option 2
BAU Member States are primarily responsible on deciding on the detail tasks of DSOs.	- Allow and incentivize DSOs to acquire flexibility services from distributed energy resources. - Establish specific conditions under which DSOs should use flexibility, and ensure the neutrality of DSOs when interacting with the market or consumers. - Clarify the role of DSOs only in specific tasks such as data management, the ownership and operation of local storage and electric vehicle charging infrastructure. - Establish cooperation between DSOs and TSOs on specific areas, alongside the creation of a single European DSO entity.	- Allow DSOs to use flexibility under the conditions set in Option 1. - Define specific set of tasks (allowed and not allowed) for DSOs across EU. - Enforce existing unbundling rules also to DSOs with less than 100,000 customers (small DSOs).
Pro Current framework gives more flexibility to Member States to accommodate local conditions in their national measures.	Pro Use of flexible resources by DSOs will support integration of RES E in distribution grids in a cost-efficient way. Measures which ensure neutrality of DSOs and will guarantee that operators do not take advantage of their monopolistic position in the market.	Pro Stricter unbundling rules would possibly enhance competition in distribution systems which are currently exempted from unbundling requirements. Under certain condition, stricter unbundling rules would also be a more robust way to minimizing DSO conflicts of interest given the broad range of changes to the electricity system, and the difficulty of anticipating how these changes could lead to market distortions.
Con Not all Member States are integrating required changes in order to support EU internal energy market and targets.	Con Effectiveness of measures may still depend on remuneration of DSOs and regulatory framework at national level.	Con Uniform unbundling rules across EU would have disproportionate effects especially for small DSOs. Possible impacts in terms of ownership, financing and effectiveness of small DSOs. A uniform set of tasks for DSOs would not accommodate local market conditions across EU and different distribution structures.
Most suitable option(s): Option 1 is the preferred option as it enhances the role of DSOs as active operators and ensures their neutrality without resulting in excess administrative costs.		

3.2.2. *Description of the baseline*

Legal framework

Article 25 ('Tasks of distribution system operators') of the Electricity Directive puts forward provisions which describe the core tasks of DSOs, as well as, specific obligations that DSOs have to comply with. Under these provisions, DSOs are mainly responsible to operate, maintain and develop under economic conditions a secure, reliable and efficient electricity distribution system.

Except these core tasks, the Electricity Directive sets under Article 25(6) some specific obligations e.g. in cases where DSOs are responsible for balancing the distribution system. Moreover, under Article 25(7), DSOs shall consider measures such as energy efficiency and demand-side management, in order to avoid investing in new capacity.

According to Article 41 of the Electricity Directive Member States are responsible to define roles and responsibilities for different actors including DSOs. These roles and responsibilities concern the following areas: contractual arrangements, commitment to customers, data exchange and settlement rules, data ownership and metering responsibility.

Article 26 of the Electricity Directive set also unbundling requirements for DSOs similar to Directive 2003/54/EC (the previous Electricity Directive which was part of the Second Package). The Electricity Directive sets unbundling requirements in terms of legal form (legal unbundling) where the DSO is a legally separate entity with its own independent decision making board, but remains under the same ownership of a vertically integrated undertaking ('VIU'). Under this form of unbundling it is also required that DSOs implement functional unbundling where the operational, management and accounting activities of a DSO are separated from other activities in the VIU. Article 31 of the Electricity Directive also requires the unbundling of accounts (accounting unbundling) where the DSO business unit must keep separate accounts for its activities from the rest of the VIU in order to avoid cross-subsidisation,.

Article 26(4) of the Electricity Directive gives the option to Member States not to apply the unbundling rules (no legal/functional unbundling) for DSOs with less than 100,000 customers. Only accounting unbundling applies to DSOs below this threshold. Member States may choose to apply this threshold or not, or to set a lower threshold. Article 26(3) contains obligations which seek to strengthen regulatory oversight on vertically integrated undertakings and to mitigate communication and branding confusion.

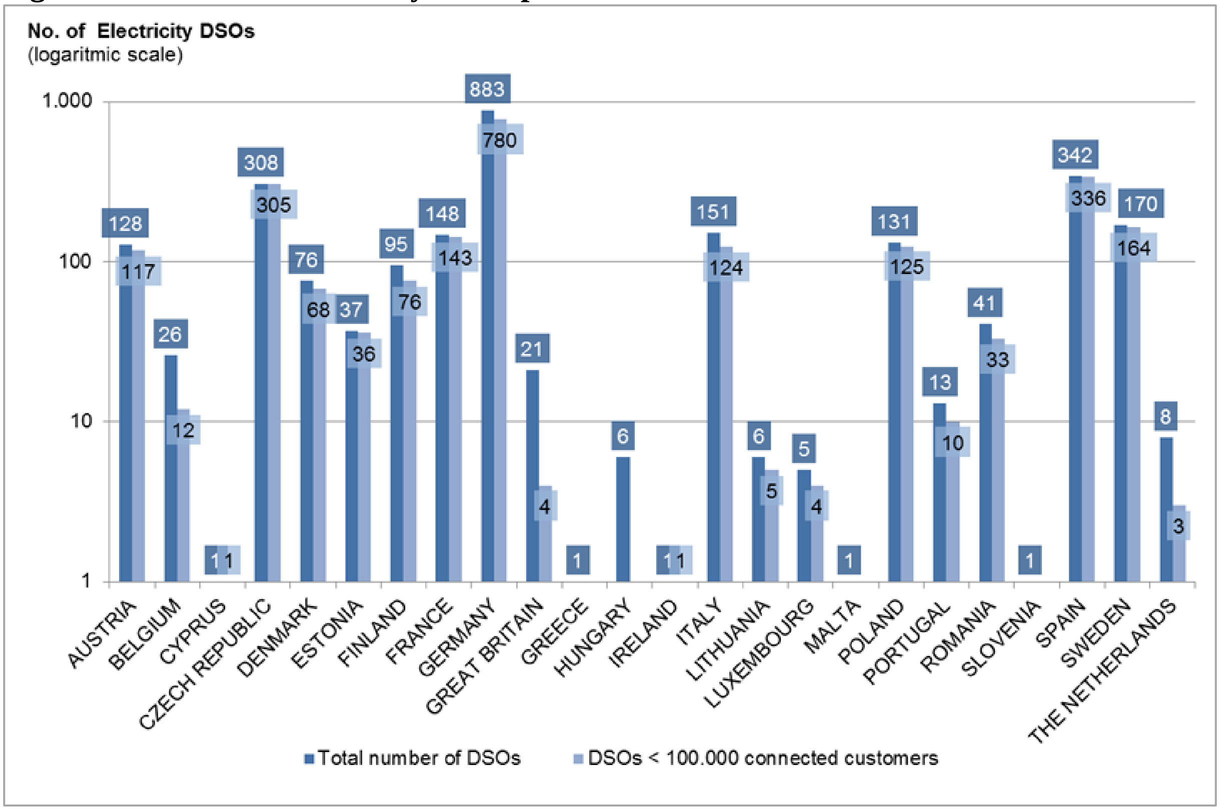
Assessment of current situation

Electricity distribution differs widely across EU Member States in terms of the number of DSOs in each country, voltage level of the distribution system, and tasks. According to CEER[153] (data for 24 EU Member States) there is a total of 2,600 electricity DSOs operating across EU (see figure 1). From these DSOs, 2,347 (around 90% of the total) fall under the 100,000 rule and according to Article 26(4), for these DSOs, Member

[153] *"Status Review on the Transposition of Unbundling Requirements for DSOs and Closed Distribution System Operators"* (2013) CEER.

States are not obliged to implement unbundling provisions under Article 26 of the Electricity Directive.

Figure 1: Number of electricity DSOs per Member State



Source: CEER (2013)

Within the framework of the Electricity Directive, Member States have to determine the detailed tasks of DSOs. There is number of factors which may affect those tasks such as: the structure and ownership of electricity distribution (i.e. public/private, municipalities etc.), development of the electricity sector, size of the DSOs, voltage level of distribution grid. For instance, in Member States with a high number of DSOs two layers of distribution systems usually exist, local distribution systems and regional distribution systems which connect local networks with the transmission network.

According to the Electricity Directive the core tasks of DSOs are to maintain, develop and operate the distribution network. The Electricity Directive does not allocate other specific tasks to DSOs such as for instance metering or data management activities. The more specific activities are left to Member States to decide, according for instance to Article 41. According to the Electricity Directive DSOs may also perform balancing activity, this may be the case in some Member States for regional or larger DSOs.

Therefore, as the EU legislation leaves a quite open framework, there is a variety of tasks for which DSOs are responsible, depending on the Member State where they are operating. For instance, even in activities such as metering and connection that in the majority of the Member States is traditionally performed by the DSOs, there are cases (e.g. UK) where the activity is open to competition.

When it comes to tasks which can be performed both by TSOs and DSOs there is a mixed picture across the EU. In general, tasks such as dispatching of generation and use of flexibility resources are part of TSO tasks. In the majority of Member States where DSOs can be involved in dispatching activities, this is mostly in cases of emergency in order to ensure security of supply. Cases where flexibility resources or interruptible contracts can be used by DSOs are rather limited[154].

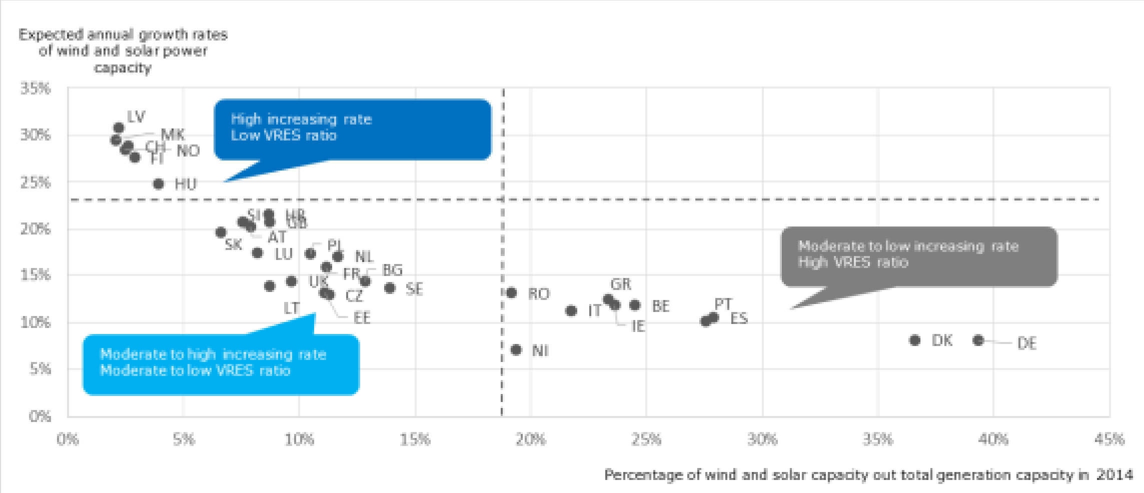
In meeting the 2020 targets and 2030 climate and energy objectives[155], Member States will have to integrate a high amount of RES with an increasing number of these resources being variable RES E (wind and solar). A large share of these resources is connected to distribution grids (low and medium voltage); according to available data[156] this number is estimated to be even higher than 90% in some Member States (e.g. Germany) and over 50% in others (Belgium, UK, France, Ireland, Portugal, and Spain).

Moreover, the electrification of sectors such as transport and heating will introduce new loads in distribution networks. These elements will create new requirements and possibilities[157] for DSOs, who will have to manage higher peaks in demand while maintaining quality of service and minimizing network costs.

The degree of the challenge of integrating high amounts of variable RES (VRES) in networks differs among the Member States. A group of Member States such as for example Germany, Denmark, Spain, Portugal already have integrated significant amounts of wind and solar power in the grid and are expecting more moderate growths rates in VRES capacity going forward to 2030 (see figure 2). The majority of Member States have integrated a moderate amount of wind and solar power but will experience higher growth rates of VRES compared to the group with a high VRES ratio. A minority of Member States have VRES ratios of less than 5% but are expected to have the highest growth rates going forward to 2030.

[154] *"Study on tariff design for distribution systems"* (2015) AF Mercados, refE, Indra.
[155] COM(2014) 15 final *"A policy framework for climate and energy in the period from 2020 to 2030"*.
[156] EvolvDSO project (Deliverable 1.1) and other sources.
[157] On the one hand EVs and heating/cooling loads will require more network capacity, on the other hand this kind of loads offer a huge storage potential (i.e. battery and heat storage) which can be coordinated in order to offer flexibility services to the system.

Figure 2: Wind and solar growth rates and ratio to total capacity



Source: Copenhagen Economics, VVA Europe (2016).

Distribution grids will also face an increasing challenge from the integration of new loads resulting from electric vehicles (EV) penetration and heat pumps. Currently, penetration rates for electric vehicles are low among the European countries ranging from around 700 cars in Portugal to 44,000 cars in the Netherlands (see table 1). However, the uptake of electric vehicles is expected to increase by over 50% per year going forward to 2030 in several EU Member States. Germany is expected to have the highest number of electric vehicles with over 10 million cars in 2030.

Table 1: Number of Electric Vehicles in selected countries (2014 – 2030)

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

Source: Copenhagen Economics, VVA Europe (2016).

Cost-effectively adapting to these changes will require DSOs to use flexible distributed energy resources (e.g. demand response, storage, distributed generation etc.) to manage local congestion, which will also require enhancing DSO/TSO collaboration. The use of such flexibility for the operation and planning of the network has the potential to avoid costly network expansions. For example, it may be significantly cheaper for a DSO to overcome local network congestion by occasionally procuring demand response services than to upgrade its entire network infrastructure in an area to be able to accommodate relatively uncommon demand peaks. This is a pressing issue for the EU in light of the fact that electricity network costs increased by 18.5% for households and 30% for industrial consumers between 2008 and 2012[158].

For instance, a study[159] conducted for the German distribution networks estimated that under the current conditions and depending on different scenarios, a considerable additional overall investment will be required. The study concludes that innovative planning concepts in conjunction with intelligent technologies considerably reduce the network expansion requirement[160].

In the majority of Member States presented in table 2, DSOs cannot currently procure flexibility services partially because there is a lack of a legal framework or because the services are not covered in the regulated cost base.

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158 COM(2014) 21 /2 *"Energy prices and costs in Europe"*

159 *"Moderne Verteilernetze für Deutschland(Verteilernetzstudie)"* (2014) E-Bridge, IAEW, OFFIS.

160 According to the study 90% of the capacity of installed renewable energy installations is connected up to distribution networks. With an overall coverage of 1.7 million kilometres, these networks make up about 98% of the overall national grid in Germany. An amount of 23 billion euros to 49 billion euros depending on the scenario must be invested in distribution networks by 2032 for the integration of renewable energy installations. The combination of innovative planning concepts with intelligent technologies can halve the investment requirement and reduce by 20% the average supplementary costs.

Table 2: Status Quo on DSOs incentives to procure flexibility services

Procurement of flexibility services	Number of Member States	Member state
DSOs cannot contract flexibility services	8	FI, FR, IE, IT, PT, EL, NL, ES
DSOs can contract system flexibility services for constraints management in certain situations	3	UK, BE, DE

Source: Copenhagen Economics, VVA Europe (2016).

According to EvolvDSO project[161] most DSOs surveyed (France, Ireland, Italy, Portugal) are not able to contract flexibility for congestion management although discussions on the topic take place in these countries. In Belgium and Germany, DSOs have the possibility to obtain system flexibility services via the connection and distribution access contract. These types of contracts provide for instance a reduced network fee in exchange for the control of the unit.

In Belgium, such contracts apply to new production units requesting connection at HV and MV grids. The contract allows to temporarily limit the active power of the unit via distance control. In Germany DSOs offer these "non-firm" access contracts to controllable thermal loads, i.e. heat pumps and overnight storage heating (EvolvDSO, 2016). Both countries are considering broadening these contracts to also include flexibility contracts for congestion management under normal operation state and not just emergency situations (EvolvDSO, 2016).

From data presented in the study by AF Mercados et al (2015) regarding the responsibility of DSOs in dispatching of embedded generation, use of interruptible contracts and other sources of flexibility, it is concluded that in most of Member States where DSOs can be involved in dispatching this is most of the times for coping with emergency situations (security reasons). In less than 1/3 of the Member States DSOs are using solutions such as flexibility resources or interruptible contracts in order to address grid problems.

3.2.3. <u>*Deficiencies of current legislation*</u>

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.evolvdso.eu/Home/About).

The risks of less unbundling link to suboptimal switching procedures in order to deter market entry, competitive advantage which may come from the use of the same brand name or privileged access to network information, consumption data information and cross-subsidies.

On the other hand, discrimination for distribution network access appears to be less relevant than at transmission level, with a possible exception of small generation connected at distribution level. DSO unbundling is less relevant with respect to cross-border flows as flows are more local.

CEER finds that in general the implementation of unbundling rules has been satisfactory[162]. Regarding the implementation of the measures, CEER is reporting problems in the implementation of the provisions related to branding and communication. The Commission has taken action towards the proper implementation of the relevant provisions through compliance checks and infringement procedures, requesting Member States to ensure a clear separation of identity of the supply and distribution activities within a vertically integrated undertaking.

Some of the factors that may influence and raise the impact of the foreseen risks are the increased penetration of RES E generation at distribution level and introduction of smart metering systems.

In terms of **effectiveness**, the intervention mainly aimed at the unbundling of vertical integrated distribution companies with the objective to ensure non-discriminatory and transparent third party access in distribution networks, in order to promote competition in the energy market. There is no evidence that the intervention within the boundaries of the unbundling requirements, did not achieve the objective of promoting competition in the market.

The Electricity Directive leaves it at the discretion of Member States to decide which level of unbundling will apply for small DSOs (less than 100,000 customers) and the detailed tasks that DSOs should carry out at a national level. There is a quite diverse situation across EU Member States when it comes to responsibilities of DSOs across the EU.

Provisions which aimed to enhance the DSOs position in using demand side management and energy efficiency measures in planning their networks did not prove to be effective. Only in few Member States, DSOs are in position to use such tools in order to avoid costly investments and operate their networks more efficiently.

In terms of **relevance**, the original objectives of DSO unbundling requirements and the framework in which Member States can decide on the responsibilities of operators still correspond to the EU objective of a competitive internal energy market. The implementation of smart metering systems (wide scale roll-out in 17 Member States) will generate more granular consumption data and new business opportunities in the retail market. Moreover, the introduction of more RES E generation at distribution level will require a more active management of the network from DSOs. Even if the measures under the Electricity Directive had included to a certain extent these developments the

162 *"Status Review on the Implementation of Distribution System Operators' Unbundling Provisions of the 3rd Energy Package"* (2016) CEER.

focus of the intervention was not on these new needs that are estimated to grow with the completion of smart metering systems and the installation of distributed RES E.

In terms of **coherence**, the measures are fully coherent with the objectives of the internal energy market. Unbundling provisions for DSOs complement the relevant requirements for TSOs, by providing a transparent and non-discriminatory framework for third party access also at retail market level. These provisions are fundamental for the promotion of competition in the energy market, the entrance of new energy service providers and the development of new services.

In terms of **EU-added value**, the requirements on unbundling are fundamental for the promotion of competition in the internal energy market. Provisions which are relevant to DSOs have the characteristic of a permanent effect.

Gap analysis

According to the conclusions of the *"Evaluation of the EU's regulatory framework for electricity market design and consumer protection in the fields of electricity and gas"* with the deployment of smart metering systems across EU Member States a large amount of data will be available to DSOs. This development requires a closer assessment and consideration of specific measures.

In terms of DSO responsibilities, it is clear that there is a wide variety of roles and tasks for DSOs across the EU. This situation does not allow for the application of a uniform set of responsibilities for all DSOs, as such measure would have a disproportionate effect on DSOs across the EU, based mostly on the variety of distribution voltage levels and number of connected customers.

It seems however appropriate to enhance the role of DSOs when it comes to additional tools such as the use of flexible resources in order to improve their efficiency in terms of costs and quality of service provided to system users. Such measures however could only be introduced with the parallel introduction of suitable provisions which prohibit DSOs to take advantage of their monopolistic position in the market by clarifying their role in specific activities. In the absence of such measures, the DSOs could foreclose the market and reduce the benefits for the system users, leading to an inefficient allocation of resources and reduction of social welfare.

3.2.4. *Presentation of the options*

Distribution system operators

Under **Option 0** (BAU) existing provisions of the Electricity Directive will continue to apply concerning the tasks of DSOs. In this case Member States are responsible for deciding on a number of non-core tasks as well as on remuneration of DSOs.

Option 0+ (Non-regulatory approach) was discarded as the existing EU legislative framework does not directly address flexibility in distribution networks. This needs to be further codified in law in order to ensure, *inter alia*, a level playing field for the achievement of the EU's RES E deployment objectives given new market conditions. In addition, it is unlikely that voluntary cooperation between Member States would deliver the desirable policy objectives in this case.

Under **Option 1** the objective is to allow the DSOs to procure and use flexibility services. Introduce specific conditions under which DSOs should procure flexibility in order to ensure neutrality and enable longer term investments in flexibility. Moreover, the role of DSOs regarding specific tasks such as data management, ownership and operation of storage and electric vehicle charging infrastructure will be clarified under this option. Measures under Option 1 will also seek to establish an enhanced cooperation between TSOs and DSOs in terms of network operation and planning.

Under **Option 2** measures will aim to define specific tasks that DSOs across the EU should be allowed and not allowed to carry out. The tasks that DSOs should be allowed to carry out would include their core tasks and tasks where there is no potential competition, while activities which are open to competition or already forbidden (e.g. generation or supply) should not be allowed. Also, under this option existing unbundling rules will apply also to DSOs with less than 100,000 customers (small DSOs), abolishing the provision of the Electricity Directive which allows Member States to exempt small DSOs from legal and functional unbundling.

3.2.5. *Comparison of the options*

a. The extent to which they would achieve the objectives (effectiveness)

The main objective is to enable DSOs to locally manage challenges of the energy transition in a cost-efficient and sustainable way, without distorting the market.

In general the current EU framework leaves to Member States the more detailed identification of the distribution framework at national level in terms of the specific tasks that DSOs should carry out and the tools available for operating and developing their grids. However, in light of the major changes the electricity system is undergoing, **Option 0** is likely to be inadequate in ensuring a cost efficient grid operation.

DSOs may in some countries not have access to appropriate tools in order to operate efficiently, for instance by procuring flexibility from their customers through aggregators or local markets, while in many countries they are not adequately incentivised through the remuneration schemes in place to do so. The Electricity Directive requires DSOs to take into account demand-side management and energy efficiency measures or distributed generation as well as conventional assets expansion when planning their networks. However, it is up to Member States (national authorities, NRAs and DSOs) to ensure that this is carried out. While this option provides an open EU framework for Member States, it is also likely to lead to national specific frameworks which are not conducive to the use of demand side flexibility at DSO level.

Moreover, there are different approaches across Member States for the use of demand side flexibility from DSOs and a lack of market rules under which DSOs shall procure flexibility services, while there is no clear framework regarding the involvement of DSOs in activities such as storage or electric vehicle charging infrastructure.

The measures under **Option 1** will establish a clear legal basis for allowing DSOs to use flexibility. Specific measures under this option will also clarify the role of DSOs in competitive activities such as storage and electric vehicles charging, and set a specific framework for DSO involvement. Such a regulatory framework should allow different solutions in order to address specific needs of the network, based on market procedures (e.g. long-term contracting of flexibility services such as large scale storage). Regarding the involvement of DSOs in data handling, specific measures under Option 1 will ensure neutrality of operators (see also Annexe 7.3 of the present annexes to the impact assessment).

DSOs should harness flexibility from grid users without the risk of distorting or hampering the development under competitive terms of distributed energy services, such as demand response, storage, supply and generation, through discriminatory practices or monopolistic behaviour. This Option will reduce the risk of competition distortions compared to Option 0. By defining a common framework on how DSOs can procure flexibility and perform specific roles such as involvement in storage, a level playing field of a certain standard will be ensured across Member States, unlike the situation where Member States adopt different approaches to this issue. Moreover, cooperation with TSOs is important as resources which provide flexibility to the system are located in the distribution system and therefore coordinated operation and exchange of information between operators will be required.

Effectiveness of this option can be limited by the fact that the differences among distribution system structures and tasks of DSOs across the EU, will possibly require that measures at EU level have to remain broad enough in order to accommodate diverse situations.

Regarding the use of flexibility, the effectiveness of this option also depends on the implementation in each Member State, as national remuneration schemes are important in order to provide to DSOs the right incentives to use flexibility and be properly remunerated (links to options under distribution tariffs and remuneration, see also Annexe 3.3 of the present annexes to the impact assessment).

Option 2 foresees a uniform framework for DSOs in terms of tasks and level of unbundling across the EU. The procurement of flexibility from DSOs will be similar to Option 1.

Stricter unbundling rules for small DSOs may lower the risk for discriminatory behaviour and result in gains in retail competition. On the other hand, given that DSOs are natural monopolies, such measures will not fully guarantee the avoidance of the dominant role of DSOs in procuring flexibility from system users. Therefore, additional measures will be needed in order to avoid monopolistic behaviour from DSOs which could lead to market distortions.

The definition of a uniform set of tasks applicable to all DSOs could lead to non-effective arrangements depending on the different market conditions as such a framework would not be able to account for the differences between distribution systems across the EU (e.g. different retail market conditions or structural and technical differences of distribution systems)[163].

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

[163] CEER in its public consultation paper "*The future role of DSOs*" (2014), proposes a set of potential DSO activities categorized under three broad areas (core activities, 'grey area' activities and forbidden activities). In its conclusion paper (2015), CEER remarks that there is no single model for what a DSO can and cannot do, but rather a number of grey areas where DSOs can participate under certain conditions.

Impacts of measures under **Option 1** will be highly dependent on the detailed implementation at national level, as for instance the extent to which DSOs under the monitoring of the NRA will decide to supplant grid expansions with the use of flexibility in network planning. The decision of such measures will be made on the basis of the most beneficial solution for each distribution system taking into account avoided investments and considering the costs of employing flexible resources.

Curtailment of RES E in grid planning as quantified in the E-Bridge et al (2014) study[164] could help reducing the grid expansion requirements caused by new RES E installations in the future by at least 22% in the higher voltage grid (>110 kV). Those savings of 22% can be achieved when allowing for 3% curtailment in grid planning. Considered generation for curtailment are wind and solar power installations larger than 7 kW; that affects 52% of all installations, whose aggregated capacity accounts for more than 90% of the total capacity installed. The benefits of curtailment are lower expansion requirements for the grids, which do not have to be built to accommodate flows corresponding to the maximum capacity of the connected RES E installations.

Copenhagen Economics, VVA Europe (2016)[165] estimate that the total savings at EU level from avoided distribution grid investments will be in the order of at least EUR 3.5 to 5 billion in yearly investments towards 2030 (table 3). This corresponds to a total of approximately EUR 50-85 billion accumulated from 2016. In practice, the potential savings could be significantly higher, to the extent which supply and demand side flexibility measures can be used in combination rather than each measure in isolation.

Table 3: Avoided grid investments from flexibility

Extra grid investment from increased DG and load growth (EUR billion) yearly at EU level	11
Savings from demand flexibility alone (percent)	30 - 55
Savings from supply flexibility alone (percent)	44 - 55
Savings from combination of demand and supply flexibility (percentage)	At least 30-44
Very conservative estimate of avoided extra grid investments from flexibility yearly at EU level (EUR billion)	**3.5 to 5**

Source: Copenhagen Economics, VVA Europe (2016).

McKinsey & Company (2015)[166] found that energy storage can absorb a large share of the power that would otherwise been curtailed even in a scenario with high share of variable renewable power, and most of the flexibility would be located on the distribution grid level. Decisions on which source of flexibility is more efficient should be made on the basis of the specific needs of the network according to transparent, non-discriminatory and market-based procedures, under close regulatory control.

164 *"Moderne Verteilernetze für Deutschland (Verteilernetzstudie)"* (2014) E-Bridge, IAEW, OFFIS.

165 *"Impact assessment support study on: Policies for DSOs, Distribution Tariffs and Data Handling"* (2016) Copenhagen Economics, VVA Europe..

166 "*Commercialisation of energy storage in Europe"* (2015) McKinsey & Company.

Related measures are expected to create net benefits for the electricity system as they will lower distribution costs. Moreover, the use of flexibility from distribution system operators will stimulate the introduction of new services and the market entrance of new players such as aggregators. Consumers will benefit from lower network tariffs (reflecting lower distribution costs) and directly by participating in demand response programmes or other services to the DSO.

The clarification of the EU framework regarding the role of DSOs in specific tasks such as data handling, storage and electric vehicle charging, is expected to have positive net benefits for the electricity system and positive economic societal net benefits. The main reason is that these tasks can be carried out more efficiently by market players rather than natural monopolies. Measures under this option will allow certain exemptions in cases where a market is new (e.g. electric vehicles) or where there is no interest from market parties to invest in such activities.

Option 2 would result in higher costs as small DSOs (serving less than 100,000 customers) would have to implement legal unbundling criteria. Such an option would lead small DSOs to separate distribution from the supply activity of the VIU and possibly merge with larger DSOs, resulting in one-off and structural costs which differ per Member State. On the other hand, main benefits would result from more transparent third party access which could potentially have positive impacts on competition. Such costs and benefits are hard to be fully quantified as many parameters and different local conditions should be taken into account.

c. Simplification and/or administrative impact for companies and consumers

Option 2 for distribution system operators is expected to have high administrative costs on the concerned energy companies because of the unbundling requirement on small DSOs (less than 100,000 customers) which is expected to require a restructuring of those energy companies affected by the measures.

d. Impacts on public administrations

Impacts on public administration are summarized in Section 7 below.

e. Trade-offs and synergies associated with each option with other foreseen measures

Option 1 for distribution system operators demonstrates multiple synergies with options under demand response and smart metering. Demand response programmes through aggregators can provide services to DSOs who wish to use flexibility in network operation and planning.

f. Likely uncertainty in the key findings and conclusions

There is a medium risk associated with the uncertainty of the assessment of costs and benefits of the presented options. However, it is considered that this risk cannot influence the decision on the preferred option as there is a high differentiation among the presented options in terms of qualitative and quantitative characteristics.

g. Which Option is preferred and why

Option 1 is the preferred option as it demonstrates the higher potential net benefits for electricity system and society and expected to demonstrate additional benefits compared to Option 0 without resulting in excessive costs for the involved parties. Consumers will benefit from lower distribution costs and improved competition in the market.

3.2.6. *Subsidiarity*

EU has a shared competence with Member States in the field of energy pursuant to Article 4(1) TFEU. In line with Article 194 of the TFEU, the EU is competent to establish measures to ensure the functioning of the energy market, ensure security of supply and promote energy efficiency.

Under the energy transition, distribution grids will have to integrate even higher amounts of RES E generation, while new technologies and new consumption loads will be connected to the distribution grid. Distributed generation has the potential directly or through aggregation to participate in national and cross-border energy markets. Moreover, other distributed resources such as demand response or energy storage can participate in various markets and provide ancillary services to the system also with a cross-border aspect.

Moreover, DSOs should have the ability to integrate new generation and consumption loads under cost-efficient terms. The access conditions for RES E generation and other distributed resources shall be transparent and the DSO's role should be neutral in order to create a level playing field for these resources. As the amount of resources such as RES E generation, but in the future also other resources such as storage, will increase, the conditions under which these resources can access the grid and participate in the national and cross-border energy markets is expected to become more relevant.

The neutrality of DSOs when they are using flexibility to manage local congestion is a precondition for well-functioning retail market. While electricity distribution can be considered a local business, harmonised rules ensuring neutrality of DSOs towards other market actors including new energy services providers create a level playing field for RES E development across the EU, crucial in achieving the RES E targets, and support the completion of internal energy market.

Distribution grid issues may affect the development of the internal energy market and raise concerns over possible discrimination among system users from different Member States who however have access in the same energy markets. Uncoordinated, fragmented national policies at distribution level may have indirect negative effects on neighbouring Member States, and distort the internal market. EU action therefore has significant added value by ensuring a coherent approach in all Member States.

3.2.7. *Stakeholders' opinions*

3.2.7.1. *Results of the consultation on the new Energy Market Design*

According to the results of the public consultation on a new Energy Market Design[167] the respondents view active distribution system operation, neutral market facilitation and

[167] https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

data hub management as possible functions for DSOs. Some stakeholders pointed to a potential conflict of interests for DSOs in their new role in case they are also active in the supply business and emphasized that the neutrality of DSOs should be ensured. A large number of the stakeholders stressed the importance of data protection and privacy, and consumer's ownership of data. Furthermore, a high number of respondents stressed the need of specific rules regarding access to data.

Governance rules for DSOs and Models of data handling

Question: *"How should governance rules for distribution system operators and access to metering data be adapted (data handling and ensuring data privacy etc.) in light of market and technological developments? Are additional provisions on management of and access by the relevant parties (end-customers, distribution system operators, transmission system operators, suppliers, third party service providers and regulators) to the metering data required?"*

Summary of findings:

Regulators stress the importance of neutrality in the role of the DSOs as market facilitators. To achieve this will require to:

- Set out exactly what a neutral market facilitator entails;
- When a DSO should be involved in an activity and when it should not;
- NRAs to provide careful governance, with a focus on driving a convergent approach across Europe.

Regulators consider that consumers must be guaranteed the ownership and control of their data. The DSOs, or other data handlers, must ensure the protection of consumers' data.

IFIEC considers that DSOs should not play the role of market facilitator, the involvement of a third party is perceived to better support neutrality and a level playing field. Moreover, coordination of TSOs and DSOs and potentially extended role of DSOs with respect to congestion management, forecasting, balancing, etc. would require a separate regulatory framework. However, IFIEC express concerns that some smaller DSOs might be overstrained by this. Extended roles for DSO should be in the interest of consumers and only be implemented when it is economically efficient.

EUROCHAMBERS believes that due to different regional and local conditions a one size fits all approach for governance rules for distribution system operators is not appropriate. The EU could support Member States by developing guidelines (e.g. on grid infrastructures and incentive systems).

Most energy industry stakeholders (CEDEC, EDSO, ESMIG, ETP, EUROBAT, EWEA, GEODE) believe that the role of DSOs should focus on active grid management and neutral market facilitation. Some respondents state that the current regulatory framework prevents DSOs from taking on some roles, such as procurer of system flexibility services and to procure balancing services from third parties, and such barriers should be eliminated.

Also SEDC envisages that DSOs should be neutral market facilitators where unbundling is fully implemented. However, in this scenario DSOs should not be active in markets such as for demand response, as this would undermine their neutrality.

3.2.7.2. *Public consultation on the Retail Energy Market*

According to the results of the 2014 public consultation on the Retail Energy Market[168] the majority of the respondents consider that DSOs should carry out tasks such as data management, balancing of the local grid, including distributed generation and demand response, and connection of new generation/capacity (e.g. solar panels).

According to the majority of the stakeholders these activities should be carried out under good regulatory oversight, with sufficient independence from supply activities, while a clear definition of the role of DSOs (and TSOs), but also of the relationship with suppliers and consumers, is required.

3.2.7.3. *Electricity Regulatory Forum - European Parliament*

Relevant conclusions of the 31st EU Electricity Regulatory Forum:

- *"The Forum stresses the importance of innovative solutions and active system management in distribution systems in order to avoid costly investments and raise efficiencies in system operation. It highlights the need for DSOs to be able to purchase flexibility services for operation of their systems whilst remaining neutral market facilitators, as well as the need to further consider the design of distribution network tariffs to provide appropriate incentives. The Forum encourages regulators, TSOs and DSOs to work together towards the development of such solutions as well as to share best practices."*

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[168] https://ec.europa.eu/energy/en/consultations/consultation-retail-energy-market

3.3. Distribution network tariffs and DSO remuneration

3.3.1. *Summary table*

a. Table 1: Remuneration of DSOs

Objective: A performance-based remuneration framework which incentivize DSOs to increase efficiencies in planning and innovative operation of their networks.		
Option: 0	**Option 1**	**Option 2**
BAU Member States (NRAs) are mainly responsible on deciding on the detailed framework for the remuneration of DSOs.	- Put in place key EU-wide principles and guidance regarding the remuneration of DSOs, including flexibility services in the cost-base and incentivising efficient operation and planning of grids. - Require DSO to prepare and implement multi-annual development plans, and coordinate with TSOs on such multi-annual development plans. - Require NRAs to periodically publish a set of common EU performance indicators that enable the comparison of DSOs performance and the fairness of distribution tariffs.	Fully harmonize remuneration methodologies for all DSOs at EU level.
Pro Current framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro Performance based remuneration will incentivise DSOs to become more cost-efficient and offer better quality services. It would support integration of RES E and EU targets.	Pro A harmonized methodology would guarantee the implementation of specific principles.
Con Current EU framework provides only some general principles, and not specific guidance towards regulatory schemes which incentivize DSOs and raise efficiencies.	Con Detailed implementation will still have to be realized at Member State level, which may reduce effectiveness of measures in some cases.	Con A complete harmonisation of DSO remuneration schemes would not meet the specificities of different distribution systems. Therefore, such an option would possibly have disproportionate effects while not meeting the subsidiarity principle.
Most suitable option(s): Option 1 is the preferred option as it will reinforce the existing framework by providing guidance on effective remuneration schemes and enhancing transparency requirements		

b. Table 2: Distribution network tariffs

Objective: Distribution tariffs that send accurate price signals to grid users and aim to fair allocation of distribution network costs.		
Option: O	**Option 1**	**Option 2**
BAU Member States (NRAs) are mainly responsible for deciding on the detailed distribution tariffs.	- Impose on NRAs more detailed transparency and comparability requirements for distribution tariffs methodologies. - Put in place EU-wide principles and guidance which ensure fair, dynamic, time-dependent distribution tariffs in order to facilitate the integration of distributed energy resources and self-consumption.	Harmonization of distribution tariffs across the EU; fully harmonize distribution tariff structures at EU level for all EU DSOs, through concrete requirements for NRAs on tariff setting.
Pro Current framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro Principles regarding network tariffs will increase efficient use of the system and ensure a fairer allocation of network costs.	Pro A harmonized methodology would guarantee the implementation of specific principles.
Con Current EU framework provides only some general principles, and not specific guidance towards distribution network tariffs which effectively allocate costs and accommodate EU policies.	Con Detailed implementation will still have to be realized at Member State level, which may reduce effectiveness of measures in some cases.	Con A complete harmonisation of DSO structures would not meet the specificities of different distribution systems. Therefore, such an option would possibly have disproportionate effects while not meeting the subsidiarity principle.
Most suitable option(s): Option 1 is the preferred option as it will reinforce the existing framework by providing guidance on effective distribution network tariffs and enhancing transparency requirements		

3.3.2. *Description of the baseline*

Legal framework

According to Article 37(1) of the Electricity Directive, National Regulatory Authorities (NRAs) are responsible for setting or approving distribution tariffs or their methodologies.

Article 37(6) and Article 37(8) of the Electricity Directive set some more specific requirements for NRAs on tariff setting procedures and provide general principles. These principles require tariffs or methodologies to allow the necessary investments in the networks and ensure viability of the networks. NRAs shall also ensure that operators are granted appropriate short and long-term incentives to increase efficiencies, foster market integration and security of supply and support the related research activities.

Assessment of current situation

According to available data[169] allowed revenues (remuneration) for DSOs are set or approved by regulators in the majority of Member States, with the exception of Spain (ES), where allowed revenues are set by the Government.

In most Member States tariffs are also being set by the national regulator. However in some countries the responsibilities are shared between the regulator and the DSO, the regulator mainly defines the rules and approves the tariffs proposed by the DSO. Spain is the only country where the Government sets the tariffs. Distribution tariffs are published in all Member States. However, in Spain distribution tariffs are bundled with other tariff components, covering costs such as renewable generation fees.

There is a wide variety of remuneration schemes and tariff structures across the EU, which partly reflects the different situations and local conditions in Member States. With the exception of the UK, current incentive-based regulatory schemes place little emphasis on the output delivered by the distributor, but for quality of service schemes. Moreover, the following conclusions can be derived from the assessment of the current regulatory regimes across the EU:

- Typically DSOs are not exposed to volume risk and to the risk that their investment turns out to be less useful than expected when they were decided, for example because of lower than expected demand.
- Revenue setting mechanisms based on benchmarking are implemented in countries where the distribution sector is highly fragmented.
- Regulators and stakeholders are generally less involved in the decision-making process on distribution network development, as compared to transmission.
- Traditional tariff structures reflect a situation of limited availability of information on each consumer's responsibility in causing distribution costs and are also affected by affordability and fairness considerations.

[169] "*Study on tariff design for distribution systems*" (2015) AF Mercados, refE, Indra..

- In most countries, the share of distribution revenues from tariff components based on energy is large, resulting in an asymmetry between the structure of distribution costs (mostly fixed) and the way they are charged to consumers.
- In the electricity sector the energy tariff component applied to households represent on average 69% of the total network charge. This practice is common in most countries apart from three (The Netherlands, Spain and Sweden) where the energy charge weights between 21% and 0%.
- In the case of industrial customers the weight of the energy component is still dominant (around 60% for both small and large industrial clients) but there is more variability among countries and the corresponding weight ranges between 13% and 100%.

The current distribution tariff structures have been inherited from previous regulatory regimes, when tariff structures were a simple combination of distribution and supply costs, including fixed and variable energy costs, for services provided by a single utility. The distribution tariff is generally based on the distributed amount of energy, occasionally in a way that varies across times of the day and across seasons, but only rarely linked to peak load requirements. Historically, this type of volume based pricing structure was appropriate, as consumers with high peak load requirements also tended to be those who consumed most energy. Going forward the total costs on the system, which are correlated with the size of peak demand, will be less linked to total energy consumption.

Currently, the majority of DSO revenue is collected through volumetric tariffs, i.e. 69% of the revenue for household consumers, 54% for small industrial consumers and 58% for large industrial consumers (table 3). This also shows that most EU Member States have a two-part tariff with a capacity and/or fixed component and a volumetric element.

Table 3: Status quo on volumetric and capacity tariffs among Member States

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

Note: Bulgaria and Latvia are not included in the survey, Netherlands has a 100% capacity based tariff for households and small industrial consumers as the only country in the EU. In DK, Finland, Luxembourg and Malta time-of-use tariffs are not available for household customers.

Source: Copenhagen Economics, VVA Europe (2016) based on Mercados (2015) and Eurelectric (2013).

Only 3 Member States (Spain, Sweden and the Netherlands) have a capacity and/or fixed component that weighs over 50% of distribution tariff for household consumers. The Netherlands have a 100% capacity based tariff for households and small industrial consumers as the only country in the EU, while Romania has a 100% volumetric tariff. Between 6 and 8 Member States apply distribution tariffs where the capacity and fixed tariff weighs over 50% of the tariff for small and industrial consumers.

In 17 countries a time-of-use distribution tariff is applied, typically for non-residential consumers and with daily (night/day) or seasonal (winter/summer) structure (Mercados 2015). France has implemented tariffs that can incite demand response by introducing critical peak pricing. The critical peak pricing is for consumers with a three-phase connection where up to 21 days a year could be selected with a 24 hours' notice signal.

Table 4: Status quo on time-of-use tariffs in Member States

Tariff elements	Number of Member States	Member State
Time-of-use tariffs	17	AT, HR, CZ, DK, FI, FR, EE, GR, IR, LU, LT, MT, PL, PT, SI, ES, UK
Critical peak pricing	1	FR
"Social tariff element" to cross-subsidize low income consumer	5	ES, IT, FR, GR, PT

Source: Copenhagen Economics, VVA Europe (2016) based on Mercados (2015) and Eurelectric (2013).

Regarding charges applied to distributed generation there is a split picture among Member States for which data were available. In 8 Member States, distributed generation is subject to use of system charges while in 6 Member States no charges are applied. There is also a diverse situation regarding the connection charges that distributed generators have to pay with a wide variety of charging principles (i.e. shallow, deep, semi-deep or semi-shallow).

Table 5: Connection charges and use of system charges for distributed generation in Member States

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

Source: THINK report "From distribution networks to Smart distribution systems" (2013).

The above data demonstrate a wide variety of distribution tariff structures for consumption or generation across EU Member States. This wide variety of tariffs can be attributed to a certain extent to the different local conditions and costs structures in each country; however, distribution tariffs do not always follow specific principles or they introduce different diverse conditions for investments for EU consumers who wish to invest in new technologies including self-generation.

It is widely accepted[170] that the developments which are taking place in the distribution systems such as the integration of vast amounts of variable RES E generation or the integration of new loads (e.g. heat pumps, electric vehicles), require distribution tariffs which provide the right economic signals for the use and development of the system, allocate costs in a fair way amongst system users and provide stability for investments for DSOs and connected infrastructure.

Regarding remuneration schemes, DSOs across EU are not always encouraged through appropriate regulatory frameworks to choose the most cost-efficient investments and innovative network solutions. In many EU Member States the current regulation of DSOs does not always provide the right incentives to efficiently develop and operate the grid, and to consider new flexible resources in network planning made possible by distributed energy resources[171].

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

3.3.3. *Deficiencies of the current legislation*

The Electricity Directive provides an open framework for NRAs in Member States for setting distribution network tariffs. The current legislation already provides some principles on the elements that national regulators should consider when deciding on the remuneration methodology, the allocation of costs on different system users, tariff structure etc.

In terms of governance this framework shall continue to exist, as tariff setting is one of the expertise areas and core tasks of NRAs. However, in the context of the rapid transformation of the energy system, new generation technologies and new consumption loads will alter the traditional flows of energy in the system and impact the operation of distribution and transmission grids. Distribution tariff structures will have to induce an efficient use of the system, while remuneration schemes have to incentivise DSOs for efficient operation and planning of their networks. This will require further steps to be taken in EU legislation in order to create a common basis for the development of a competitive and open retail market and support the effective integration of RES E generation and new technologies under equal and fair terms across Member States.

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[170] See for instance the CEER conclusions paper on "*The future role for DSOs*" (2015) and the THINK report *"From distribution networks to smart distribution systems: Rethinking the regulation of European Electricity DSOs"* (2013).

[171] *"From distribution networks to smart distribution systems: Rethinking the regulation of European Electricity DSOs*" (2013) THINK.

[172] *"Innovation incentives for DSOs – a must in the new energy market development"* (2016) EURELECTRIC.

[173] 'Research, innovation and competitiveness' has been identified as one of the five dimensions of the Energy Union strategy (COM(2015) 80 final). In this context, smart grids and smart home technology are listed in the core priorities in order promote growth and jobs through the energy sector and to create benefits for the energy consumer.

CEER[174] and ACER[175] recognise that the current regulatory frameworks applied in many Member States may not fully address the new challenges such as the complex electricity flows caused by small scale generation. Addressing this kind of challenges through the regulatory framework would require the remuneration of innovative investments and the introduction of the right incentives for flexible solutions which can contribute in solving short-term and long-term congestions in the distribution grids[176].

While NRAs have enough flexibility in setting distribution tariff structures which best fit to their local conditions, often there is a lack of important principles which would lead to a fair allocation of distribution costs amongst system users or the avoidance of implicit subsidies amongst system users. Moreover, the right long-term economic signals to system users which would allow for a more rational development of the network are often not in place.

The diversity of tariff structures is also creating different conditions for system users such as RES E generators who directly or indirectly through aggregation can participate in the energy market. Different regulatory frameworks regarding the access conditions including distribution tariffs of a variety of energy resources which participate in national and cross-border energy markets could potentially distort competition in the internal energy market and negatively affect the level of investment in RES E and new technologies.

Therefore, a further clarification of the overarching principles might be necessary accompanied by measures which ensure the transparency of methodologies used and the underlying costs. In this context, issues such as fees and tariffs that distributed energy resources such as storage facilities have to pay would also need to be clarified.

A more detailed guidance to Member States should be decided on the basis of enhancing further the effectiveness of the distribution network tariff schemes across the EU in order to incentivise DSOs to raise efficiencies in their networks and to ensure a level playing field for all system users connected to distribution networks.

3.3.4. *Presentation of the options*

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

Under **Option 0** (BAU) distribution tariffs and remuneration for DSOs will continue to be set according to the current framework and principles set in the Electricity Directive. Regulatory authorities set or approve distribution tariffs or methodologies in the framework of the Third Package.

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174 *"The future role for DSOs"* (2015) CEER.

175 *"A Bridge to 2025 Conclusions Paper"* (2014) ACER.

176 The need for incentivising grid operators to enable and use flexibility, but also to improve distribution tariffs in order to incentivise an efficient consumer response, was widely recognised amongst the members of the Expert Group 3 (EG3) of the Smart Grids Task Force. The full analysis in included in the 2015 report *"Regulatory Recommendations for the Deployment of Flexibility"* (https://ec.europa.eu/energy/sites/ener/files/documents/EG3%20Final%20-%20January%202015.pdf).

A stronger enforcement and/or voluntary cooperation (Option 0+) has not been considered as the existing framework does not provide the necessary policy tools and principles for providing further guidance to Member States, while voluntary cooperation between Member States could only be used for sharing best-practices.

Under **Option 1** in addition to the existing framework, measures on key EU-wide principles and guidance regarding the remuneration of DSOs, including flexibility services (e.g. energy storage and demand response) in the cost-base and incentivising efficient operation and planning of grids will be put in place. EU-wide principles will also ensure fair, dynamic, time-dependent distribution tariffs in order to facilitate the integration of distributed energy resources including storage facilities and self-consumption. Such principles could be further detailed in an implementing act providing clear guidance to Member States.

Moreover, DSOs will have to prepare and implement multi-annual development plans, and coordinate with TSOs on such multi-annual development plans.

NRAs in addition to their existing competences will have to periodically publish a set of common EU performance indicators that enable the comparison of DSOs performance and the fairness of distribution tariffs. NRAs will also have to implement more detailed transparency and comparability requirements for distribution tariffs methodologies.

Measures under **Option 2** will aim to fully harmonize remuneration methodologies for all DSOs at EU level, as well as distribution tariffs (e.g. structures and methodologies). Full harmonization of tariff structures could include the definition of specific tariff elements (capacity or energy component, fixed charge etc.), but also specific rules on the allocation of distribution costs to the different tariff elements.

3.3.5. *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[177] show that a well-defined ToU tariff can indeed provide benefits in terms of CAPEX and OPEX for the distribution grid. The level of impact strongly depends on the specific characteristics of the grid and of the load/generation conditions.

Measures on transparency in tariff setting and distribution costs would increase the performance of the agents involved in the tariff setting process resulting in an overall higher societal benefit.

Option 2 could potentially have similar benefits as Option 1; however, if not well designed, a fully harmonized framework could have negative impacts in some Member States or particular distribution systems as one particular tariff methodology could not accommodate the specificities of different distribution systems.

c. Impacts on public administrations

Impacts on public administration are summarized in Section 7 below.

d. Likely uncertainty in the key findings and conclusions

There is a medium risk associated with the uncertainty of the assessment of costs and benefits of the presented options. However, it is considered that this risk cannot influence the decision on the preferred option as there is a high differentiation among the presented options in terms of qualitative and quantitative characteristics.

e. Which Option is preferred and why?

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

Option 1 (both for distribution tariffs and remuneration of DSOs) is the preferred option as it will improve existing framework and provide to Member States and regulators more concrete principles and guidance for tariff setting. Multiple benefits are expected for consumers and resources connected to distribution systems.

3.3.6. <u>*Subsidiarity*</u>

EU has a shared competence with Member States in the field of energy pursuant to Article 4(1) of the Treaty on the Functioning of the European Union (TFEU). In line with Article 194 of the TFEU, the EU is competent to establish measures to ensure the functioning of the energy market, ensure security of supply and promote energy efficiency.

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[177] *"Identifying energy efficiency improvements and saving potential in energy networks, including analysis of the value of demand response"* (2015) Tractebel, Ecofys.

Under the energy transition distribution grids will have to integrate even higher amounts of RES E generation, while new technologies and new consumption loads will be connected to the distribution grid. Distributed generation has the potential directly or through aggregation to participate in national and cross-border energy markets. Moreover, other distributed resources such as demand response or energy storage can participate in various markets and provide ancillary services to the system also with a cross-border aspect.

The access conditions, including distribution tariffs, for suppliers, aggregators, RES E generation, energy storage etc. shall be transparent and ensure a level playing field. As the amount of resources such as RES E generation, but in the future also other resources such as storage, will increase, the conditions under which these resources can access the grid and participate in the national and cross-border energy markets is expected to become more relevant.

Putting in place EU-wide principles on remuneration schemes will contribute in lowering the costs of distribution and support the deployment of flexibility services across the EU. Incentivising efficient operation and planning of distribution networks will result to an overall reduction of distribution costs which will facilitate the cost-efficient integration of distributed generation and support the achievement of EU RES targets. Moreover, through common principles for incentivising research and innovation in distribution grids, can have positive for European industry and contribute to employment and growth in the EU.

Distribution tariff issues may affect the development of the internal energy market and raise concerns over possible discrimination among system users of the same category (e.g. tariffs applied asymmetrically in border regions). Uncoordinated, fragmented national policies for distribution tariffs may have indirect negative effects on neighbouring Member States and distort the internal market, while lack of appropriate incentives for DSOs may slow down the integration of RES, and the uptake of innovative technologies and energy services. EU action therefore has significant added value by ensuring a coherent approach in all Member States.

3.3.7. *Stakeholders' opinions*

3.2.7.1. *Results of the consultation on the new Energy Market Design*

As concerns a European approach on distribution tariffs, the results of the public consultation on a new Energy Market Design[178] were mixed; the usefulness of some general principles is acknowledged by many stakeholders, while others stress that the concrete design should generally considered to be subject to national regulation.

Distribution tariffs

Question: *"Shall there be a European approach to distribution tariffs? If yes, what aspects should be covered; for example, framework, tariff components (fixed, capacity vs. energy, timely or locational differentiation) and treatment of own generation?"*

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[178] https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

Summary of findings:

There are split views among the respondents regarding an EU approach to distribution network tariffs. Some stakeholders (e.g. part of electricity consumers) believe that some degree of harmonisation across EU would be beneficial and reduce barriers to cross-border trade. However, only half of them advocate for a full harmonisation (e.g. specific tariff structures), while the other half is more in favour of EU wide principles.

The electricity industry and few Member States are among those who consider that setting out common principles at EU level is more advisable than a full harmonised framework for distribution network tariffs.

On the other hand, regulators, the majority of Member States and some electricity consumers, do not perceive that a "one fits all" solution is appropriate for distribution network tariffs.

All stakeholders agree that future tariff design should ensure cost efficiency and a fair distribution of network costs among grid users. The electricity industry supports the importance of the capacity, time and location tariff components in order to enhance network price signals and stimulate flexibility.

Member States:

National governments agree that distribution network tariffs should stimulate efficiency and be cost-reflective, with the possibility to easily adapt to market developments. National decisions on tariff structure and components are currently related to the division of network costs among the different system users and to the national distribution system characteristics (size and structure of the grid, demand profile of consumer, generation mix, extent of smart metering, approach to distributed generation), as well as to the different regulatory frameworks (number and roles of DSOs, national or regional distribution tariffs). Therefore, the majority of Member States consider that no further harmonisation of distribution tariffs at EU level is required (e.g. France, Sweden, Finland, Malta, Czech Republic).

Some national governments are however more open to some common approach at EU level. The Polish government proposes the possibility of continuous exchange of regulatory experience between NRAs and information on specific tariff parameters. The Slovak Republic would consider as beneficial a non-binding ACER recommendation on a methodology for distribution tariffs for NRAs, which should incentivise innovation while guaranteeing timely recovery of costs of distribution and efficient allocation of distribution costs. The Danish government suggests that a common framework would increase market transparency from a retail market perspective and would be a first step to harmonisation.

All national governments consider that any European harmonisation or framework for distribution tariffs should not preclude the differences in national policies nor prevent experimental tariff structures aiming at fostering demand side response.

Regulators:

Regulators do not perceive that "one size fits all" approach as appropriate for distribution tariffs. According to them, future tariff designs need to meet the following objectives:

- To encourage efficient use of network assets;
- To minimize the cost of network expansion;

- To seek a fair distribution of network costs among network users;
- To enhance the security and resilience of existing networks;
- To work as a coherent structure, consistent with other incentives.

Electricity consumers:

Some electricity consumers (BEUC, CEPI) advocate a design of distribution grids tariffs which encourage flexibility, reflecting the various profiles of demand response operators (e.g. ranging from industrial production sites to households running their solar PV unit). They argue that a differentiated set of price signals would incentivise demand side flexibility, but that distribution tariffs should comply with EU energy policy and that regulators should have a common understanding of the reward benefits.

Other electricity consumers (CEFIC, IFIEC) believe that harmonising the tariff methodology and structure would be beneficial and reduce barriers to cross-border trade. They support a fair distribution of grid costs between grid users and not leading to cost inefficiencies, and incentives to operators and system users in order to reduce total costs of the electricity system.

European Aluminium is in favour of a harmonized methodology for grid tariffs for the power intensive industry based on the properties and the contribution of the power consumption profile to the transmission system. Such a tariff system must, however, take into account national differences in grid system and market liquidity and maturity.

On the other hand, EURACOAL, EUROCHAMBERS and Business Europe disagree with a harmonization approach because it would not take into account the geographic, environmental, climate and energy infrastructure differences between Member States.

Energy industry:

Most of the stakeholders agree that an EU full harmonization approach to distribution tariffs is not advisable, while some common EU principles are a more preferable approach. In particular, EWEA advocates that the Commission should encourage NRAs in identifying "best practices" rather than imposing a top down harmonisation of distribution tariffs.

ESMIG, instead, believes that a more uniform approach across the EU would be beneficial.

A number of the respondents support the importance of the capacity (CEDEC, ENTSO-E, Eurelectric, ETP, GEODE), time (CEDEC, EASE, ETP, EWEA, GEODE) and location (CEDEC, ETP, EWEA, ENTSO-E) tariff components in order to enhance the network price signals and stimulate flexibility.

The energy industry stakeholders consider that network tariffs shall reflect cost-efficiency and fairness between consumers. They view self-generation as a positive development, but support that prosumers should contribute to the costs of back-up generation and grid costs and avoid that other consumers bear the burden of grid costs. In addition, they support that system charges and other levies linked to policy costs should not artificially increase the cost of electricity, acting as a bias penalizing consumption.

Network charges should provide DSOs with the required revenue to ensure that sufficient network investments are realized and especially investments in smart grids and in operational expenses improvements.

ESMIG advocates for the consideration of a "performance-based" approach, such that the DSOs remuneration would be based on the performance of the network rather than the volume of electricity.

3.2.7.2. *Public consultation on the Retail Energy Market*

Regarding distribution network tariffs, 34% of the respondents to the 2014 public consultation on the Retail Energy Market[179] consider that European wide principles for setting distribution network tariffs are needed, while another 34% are neutral and 26% disagree.

Time-differentiated tariffs are supported by ca 61% of the respondents, while the majority of stakeholders consider that cost breakdown (78%) and methodology (84%) of distribution network tariffs should be transparent.

The majority of stakeholders also consider that self-generators/auto-consumers should contribute to the network costs even if they use the network in a limited way. To this end, ca 50% of the respondents consider that the further deployment of self-generation with auto-consumption requires a common approach as far as the contribution to network costs is concerned.

3.2.7.3. *Electricity Regulatory Forum - European Parliament*

Relevant conclusions of the 31st EU Electricity Regulatory Forum:

- *"The Forum stresses the importance of innovative solutions and active system management in distribution systems in order to avoid costly investments and raise efficiencies in system operation. It highlights the need for DSOs to be able to purchase flexibility services for operation of their systems whilst remaining neutral market facilitators, as well as the need to further consider the design of distribution network tariffs to provide appropriate incentives. The Forum encourages regulators, TSOs and DSOs to work together towards the development of such solutions as well as to share best practices."*

European Parliament resolution of 26 May 2016 on delivering a new deal for energy consumers (2015/2323(INI)):

"24. Calls for stable, sufficient and cost-effective remuneration schemes to guarantee investor certainty and increase the take-up of small and medium-scale renewable energy projects while minimising market distortions; calls, in this context, on Member States to make full use of de minimis exemptions foreseen by the 2014 state aid guidelines; believes that grid tariffs and other fees should be transparent and non-

[179] https://ec.europa.eu/energy/en/consultations/consultation-retail-energy-market

discriminatory and should fairly reflect the impact of the consumer on the grid, avoiding double-charging while guaranteeing sufficient funding for the maintenance and development of distribution grids; regrets the retroactive changes to renewable support schemes, as well as the introduction of unfair and punitive taxes or fees which hinder the continued expansion of self-generation; highlights the importance of well-designed and future-proof support schemes in order to increase investor certainty and value for money, and to avoid such changes in the future; stresses that prosumers providing the grid with storage capacities should be rewarded;"

3.4. Improving the institutional framework

3.4.2. *Summary Table*

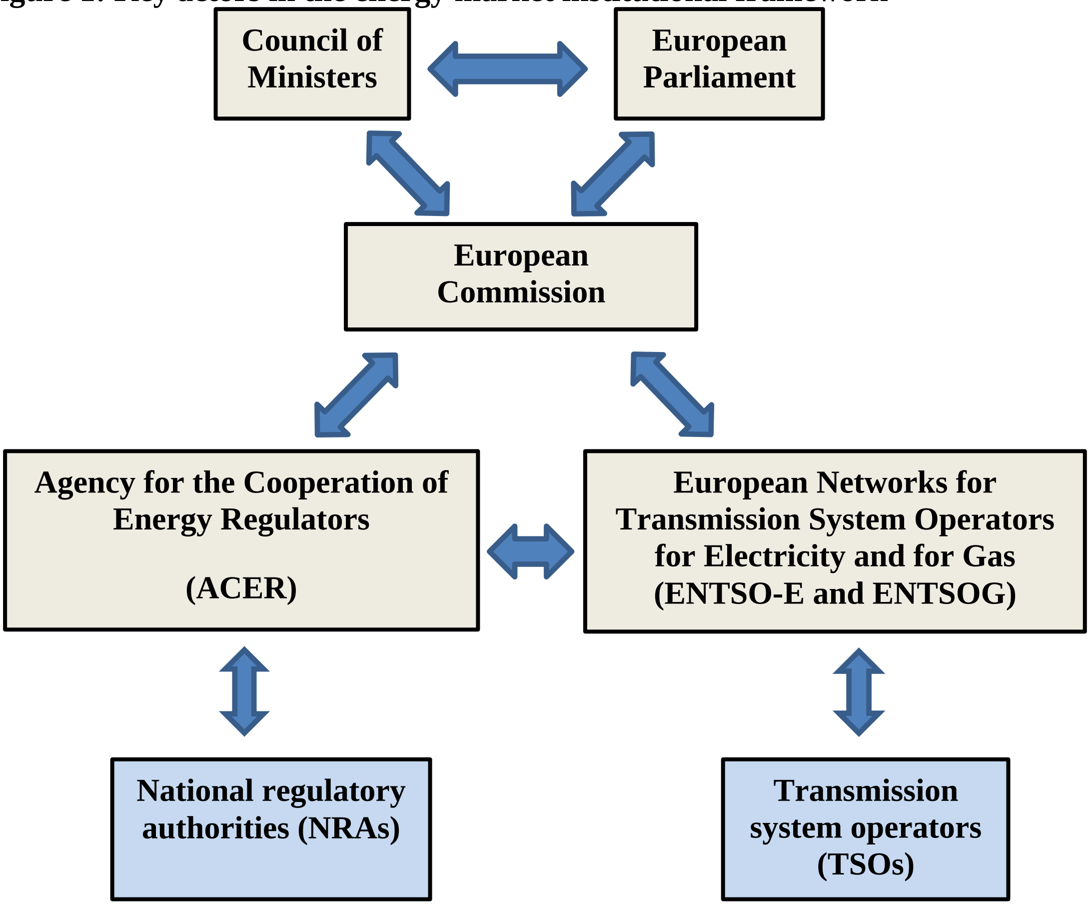
Objective: To adapt the Institutional Framework, in particular ACER's decision-making powers and internal decision-making to the reality of integrated regional markets and the proposals of the Market Design Initiative, as well as to address the existing and anticipated regulatory gaps in the energy market.			
	Option 0	**Option 1**	**Option 2**
Description	Maintain *status quo*, taking into account that the implementation of network codes would bring certain small scale adjustments. However, the EU institutional framework would continue to be based on the complementarity of regulation at national and EU-level.	Adapting the institutional framework to the new realities of the electricity system and to the resulting need for additional regional cooperation as well as to addressing existing and anticipated regulatory gaps in the energy market.	Providing for more centralised institutional structures with additional powers and/or responsibilities for the involved entities.
Pros	Lowest political resistance.	Addresses the shortcomings identified and provides a pragmatic and flexible approach by combining bottom-up initiatives and top-down steering of the regulatory oversight.	Addresses the shortcomings identified with limited coordination requirements for institutional actors.
Cons	The implementation of the Third Package and network codes is not sufficient to overcome existing shortcomings of the institutional framework.	Requires strong coordination efforts between all involved institutional actors.	Significant changes to established institutional processes with the greatest financial impact and highest political resistance.
Most suitable option(s): Option 1, as it adapts the institutional framework to the new realities of the electricity system by adopting a pragmatic approach in combining bottom-up initiatives and top-down steering of the regulatory oversight.			

3.4.1. *Description of the baseline*

The institutional framework currently applicable to the internal energy market is laid out in the Third Package. It strengthened the powers and independence of national regulatory authorities (NRAs) and mandated the creation of an Agency for the Cooperation of Energy Regulators (ACER) and the European Networks of Transmission System Operators (ENTSOs)[180], with the overarching aim of fostering cooperation amongst NRAs as well as between transmission system operators (TSOs) at regional and European level.

Figure 1 below illustrates the key actors in the energy market based on the institutional framework introduced with the adoption of the Third Package.

Figure 1: Key actors in the energy market institutional framework



Source: European Commission

[180] As the current Impact Assessment and the related legislative proposals focus on the European electricity markets, this Annex focuses on the assessment of the options with regard to the ENTSO for Electricity (ENTSO-E).

With the creation of ACER, the Third Package sought to cover the regulatory gap concerning electricity and gas cross-border issues. Prior to the adoption of the Third Package, this regulatory gap had been tackled with the Commission self-regulatory forums like the Florence (electricity) forum and the Madrid (gas) forum as well as through the independent regulatory advisory group on electricity and gas set up by the Commission in 2003, the *"European Regulators Group for Electricity and Gas"* (ERGEG). ERGEG's work positively contributed to market integration. However, it was widely recognised by the sector – and by ERGEG itself – that cooperation between NRAs should be upgraded and should take place within an EU body with clear competences and with the power to adopt regulatory decisions.

To this end, the Third Package entrusted ACER with a wide range of tasks and competences, including:

- promoting cooperation between NRAs;
- participating in the development and implementation of EU-wide network rules (network codes and guidelines);
- monitoring the implementation of EU-wide 10-year network development plans;
- deciding on cross-border issues if national regulators cannot agree or if they jointly request ACER to intervene;
- monitoring the functioning of the internal market in electricity and gas; and
- oversight over ENTSOs.

Based on the adoption of subsequent legislation on market transparency[181] and trans-European infrastructures[182] ACER has been given additional responsibilities in these areas.

The Third Package established ACER with the main mission to ensure that regulatory functions performed by NRAs at national level are properly coordinated at EU level and, where necessary, completed at EU level. As regards its governance structure[183], ACER comprises a Director, responsible for representing the Agency, for the day-to-day management and for tabling proposals for the favourable opinion of the Board of Regulators[184]. ACER's regulatory activities are formed in the Board of Regulators, composed of senior representatives of the NRAs of the 28 Member States. Its administrative and budgetary activities fall under the supervision of an Administrative Board, whose members are appointed by European Institutions. The Board of Appeal is part of the Agency but independent from its administrative and regulatory structures, and deals with complaints lodged against ACER decisions[185]. As regards the internal

181 Regulation EU No 1227/2011 on Wholesale Energy Market Integrity and Transparency – REMIT; OJ L 326, 8.12.2011, p.1

182 Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure (TEN-E Regulation).

183 See Article 3 of the ACER Regulation and related provisions.

184 Under Articles 5, 6, 7, 8 and 9 of the ACER Regulation.

185 The ACER Board of Appeal takes its decisions with qualified majority of at least four of its six members; it convenes when necessary; its members are independent in their decisions; some of its costs are envisaged in the ACER budget.

decision-making, ACER decisions on regulatory issues (e.g. opinion on network codes) require the favourable opinion of the Board of Regulators, which decides with two-thirds majority.

In relation to the creation of ENTSOs, the Third Package sought to enhance effective cooperation among TSOs in order to address the shortcomings and limitations shown by the voluntary initiatives adopted by TSOs (the European Transmission System Operators and Gas Transmission Europe). As a result, the Third Package tasked the ENTSOs with EU-level functions such as contributing to the development of EU-wide network rules, developing the 10-year network development plan and carrying out seasonal resource adequacy assessments.

The establishment of ACER and the ENTSOs in order to enhance the cooperation among NRAs and TSOs from 28 different Member States has undoubtedly been successful. Both ACER and the ENTSOs are important partners in discussions on regulatory issues. Further, the Third Package established a framwork for the ACER oversight of ENTSO-E, tasking ACER e.g. with providing opinions on ENTSO-E's founding documents, on the network code and network planning documents developed by ENTSO-E. In addition, the Agency has the obligation to monitor the execution of the tasks of ENTSO-E[186].

As regards its financing, ACER benefits from a Union subsidy set aside specifically in the general budget of the European Union, like most EU decentralised agencies. In addition, ACER can collect fees for individual decisions[187].

Network Codes and Guidelines

The Third Package has set out a framework for developing network codes with a view to harmonising, where necessary, the technical, operational and market rules governing the electricity and gas grids. Under this framework, ACER, the ENTSOs and the European Commission have a key role and need to work in close cooperation with all relevant stakeholders on the development of network codes. The areas in which network codes can be developed[188] are set out in Article 8(6) of the Electricity Regulation and of the Gas Regulation. Once adopted, these network codes become binding Commission Regulations, directly applicable in all Member States.

The network code process is defined in Articles 6 and 8 of the Electricity and the Gas Regulations and it can be essentially divided in two phases: (i) the development phase; and (ii) the adoption phase.

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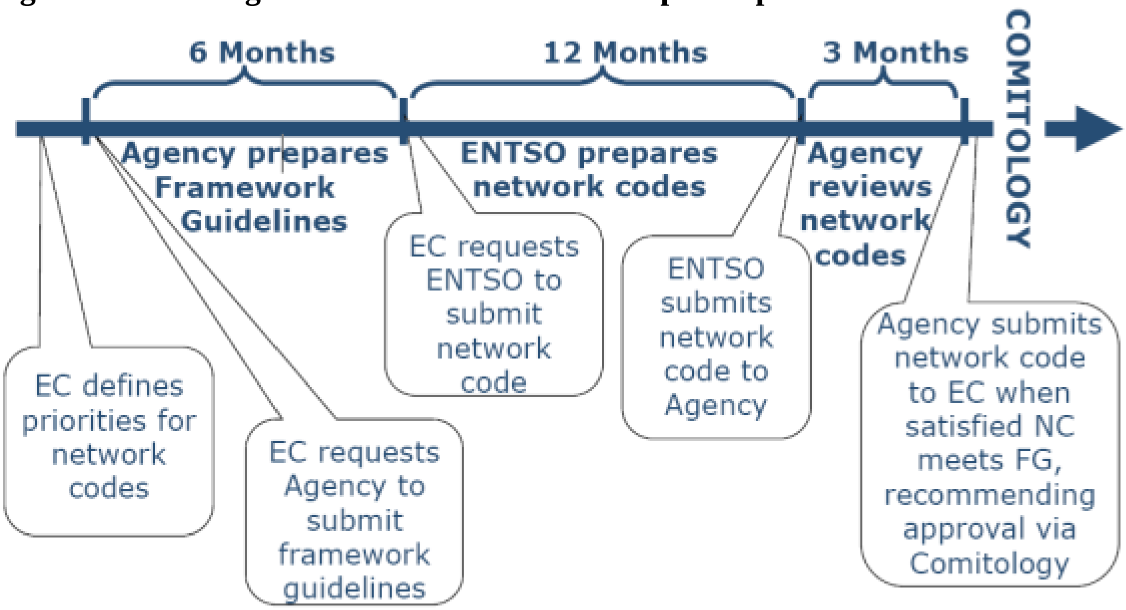
186 Art. 6 of ACER Regulation.

187 Art. 22 of ACER Regulation. However, the fee has to be set by the European Commission, which did not take place yet.

188 E.g., network connection, third party access, interoperability capacity allocation and congestion management rules, etc.

Figure 2 below illustrates the main stages of the network code development phase. It is important to note that during each of these stages, the Commission, ACER and the ENTSOs consult the proposals with stakeholders[189].

Figure 2: Main stages of the network code development process



Source: ACER

Once ACER submits a network code to the Commission recommending its adoption, the Commission starts the adoption phase ("Commission adoption phase"), illustrated in **Figure 3**[190].

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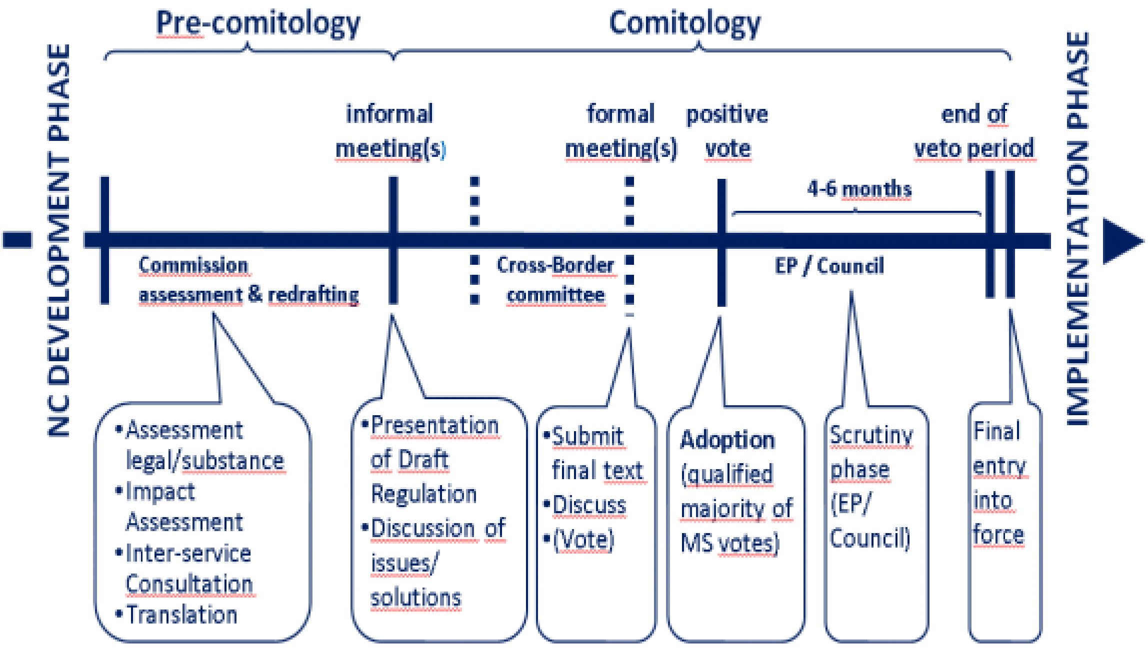
[189] These stakeholder consultations are not always required. For example, consultation is a requirement as regards the preparation of the annual priority list (see Art. 6(1) Electricity Reg.) and the preparation of the framework guidelines (Art. 6(3) Electricity Reg.). During the preparation of the network codes, the ENTSOs have carried out stakeholder workshops, although this is not formally required in the Electricity or Gas Regulations. In addition, the Agency may consult with stakeholders during the 3 months period for revision of the ENTSO proposal and the preparation of the reasoned opinion (Art. 6(7) Electricity Reg.).

[190] Network codes are adopted according to Art. 5a (1) to (4) of Decision 1999/468/EC ("*regulatory procedure with scrutiny*"), which requires a positive vote by a qualified majority of Member States and agreement from Council and Parliament.

Figure 3: Network code adoption phase



Source: unknown

The European Commission has also the possibility to develop "guidelines" which, similarly to network codes, form legally binding Commission Regulations. The guidelines have a different legal basis and follow a different development process[191], under which there is no formal role for ACER or ENTSO-E, while their adoption phase is the same as for the network codes.

Once adopted, network codes and guidelines are both acts implementing the Electricity and the Gas Regulations. There is no difference as concerns their legally binding effects and direct applicability.

3.4.2. *Deficiencies of the current legislation*

The Third Package institutional framework aims at fostering the cooperation of NRAs as well as between TSOs. Since their establishment, ACER and the ENTSOs have played a key role in the progress towards a functioning internal energy market. In 2014, the Commission undertook its first evaluation of the activities of the Agency[192] and concluded that ACER has become a credible and respected institution playing a

[191] The areas in which guidelines can be developed are set out in Art. 18 (1), (2), (3) Electricity Regulation and Art. 23 (1) Gas Regulation.

[192] In line with Art. 34 ACER Regulation. The Commission prepared this evaluation with the assistance of an independent external expert and including a public consultation. The evaluation covered the results achieved by the Agency and its working methods.

prominent role in the EU regulatory field while focusing on the right priorities[193]. Also, according to ACER[194], both ENTSOs have achieved a good level of performance since their establishment by the Third Package.

However, the recent developments in the European energy markets that the current Impact Assessment reflects upon and the related proposals of the Market Design Initiative require the adaptation of the institutional framwork. In addition, the implementation of the Third Package has also highlighted areas with room for improvement concerning the framework applicable to ACER and the ENTSOs.

The Agency has limited decision-making powers, as it acts primarily through recommendations and opinions. With the integration of the European electricity markets more and more cross-border decisions will be necessary (e.g. market coupling). Such decisions however require a strong regulatory framework, for which a fragmented national regulatory approach has proved to be insufficient[195]. Ultimately this fragmented regulatory oversight might constitute a barrier to the integration of the energy markets[196]. In this regard, there is consensus among market parties and stakeholders that ACER should indeed be enabled to more efficiently deal with cross-border issues[197] and to take decisions[198].

Moreover, as European energy markets are more and more integrated, it is crucial to ensure that ACER can function as swiftly and as efficiently as possible. As most of the

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[193] *"Commission evaluation of the activities of the Agency for the Cooperation of Energy Regulators under Article 34 of Regulation (EC) 713/2009"* (22. 1. 2014), European Commission, https://ec.europa.eu/energy/sites/ener/files/documents/20140122_acer_com_evaluation.pdf

[194] *"Energy Regulation: A Bridge to 2025 Conclusions Paper"* (19 September 2014) ACER Report.

[195] The existing competences of ACER for taking decisions set out in the ACER Regulation do not include the implementation of network codes and guidelines. Many trading or grid operation methods to be developed under network codes or guidelines require common EU-wide decisions or regional decisions. Given that ACER does not have competence to take EU-wide or regional decisions relating to network codes and guidelines, currently NRAs have to decide unanimously on the adoption of identical legal acts in all national legal systems within a six-month period. This renders the implementation of network codes and guidelines complex and inefficient.

[196] *"Energy Union. Key Decisions for the Realisation of a Fully Integrated Energy Market"* (2016), Study for the Committee for Industry, Research and Energy of the European Parliament: "*In several regional or EU-level projects (e.g. market coupling projects, see our case study in Annex 3) national authorities, TSOs, regulators and energy exchanges of different Member States need to cooperate. However, as they are primarily responsible for their own national gas and electricity system and market they are not always sufficiently motivated to also take supranational interests into account.* […] *This leads to complex and slow decisional and implementation processes for most cross-border projects, resulting in delayed implementations (e.g. the intra-day markets' coupling project)*." In this context, different stakeholders argue for stronger governance at EU level. For example, EPEX Spot states the need to accompany the electricity EU target model by appropriate governance architecture at European level, applicable on market coupling activities, which will be crucial to ensure an efficient day-to-day operation of such complex mechanisms.

[197] *"Energy Union. Key Decisions for the Realisation of a Fully Integrated Energy Market"* (2016), Study for the Committee for Industry, Research and Energy of the European Parliament.

[198] For instance, the Third Package does not define a regional regulatory framework beyond the generic reference to the need for NRAs to cooperate at regional level supported by ACER, which would be necessary to ensure proper oversight of regional entities or functions.

regulatory decisions require the favourable opinion of the Board of Regulators, it is equally relevant that the NRAs represented in the Board of Regulators can find agreements swiftly and efficiently, which in the past was not always the case, leading to delays or to a situation where the sufficient majority could not be reached, making it impossible for ACER to fulfil its role.

As mentioned in Section 2 above, the Third Package introduced network codes as tools for developing EU-wide technical, operational and market rules. While this process has proved very sucessful overall, the practice of the last 5 years has highlighted the existence of structural insufficiences. As an example, ENTSO-E plays a central role in developing EU-wide market rules. Therefore, the rules on its independence and transparency have to be strong and have to be accompanied by appropriate oversight rules to ensure the transparent and efficient functioning of the organisation. The reinforcement of these rules was also strongly requested by a high number of stakeholders in the Commission's public consultation on the market design initiative. Some stakeholders have mentioned that there is a possible conflict of interest in ENTSO-E's role – being at the same time an association called to represent the public interest involved e.g., in network code drafting, and a lobby organisation for TSOs with own commercial interests – and requested the adoption of measures to address this conflict[199].

The Third Package also includes elements of oversight of ENTSO-E by ACER. However, given the strong role ENTSO-E plays as a technical expert body, in particular in the development and implementation of network codes and guidelines, ACER's oversight has proved to be insufficient, for example as regards ENTSO-E's statutory documents or as regards the delivery of data to the Agency[200]. Moreover, the emergence of new entities and functions of EU-level or regional relevance through the adoption of network codes and guidelines has further enlarged this oversight gap. This is, for example, the case with the nominated electricity market operators ('NEMOs'), the market coupling operator ('MCO') function, which will together be responsible for performing cross-border day-ahead and intraday trading, a role created under the CACM Guideline, and regional security coordinators ('RSCs') in electricity. The creation of these new entities and functions has not been accompanied by tailored regulatory oversight.

The ACER Board of Appeal has a crucial function in safeguarding the validity of the Agency's decisions. Even though the Board of Appeals has been called upon only in a very limited number of times since the establishment, it has proved that its independence is crucial. Experience shows that its functioning and financing must be reaffirmed to ensure its full independence and efficiency.

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[199] For example by Eurelectric, EFET, CEDEC, Europex. This issue was also raised among the observations of the European Court of Auditors in its report *"Improving the security of energy supply by developing the internal energy market: more efforts needed" (2015)*, which stated: *"This is problematic because, although the ENTSOs are European bodies with roles for the development of the internal energy market, they also represent the interests of their individual members."*

[200] ACER exerts limited oversight (opinion on status, list of members and rules of procedures as per Art. 5 of the Electricity Regulation and monitoring of ENTSO-E's tasks as per Art. 9 of the Electricity Regulation.

Like most of the EU decentralised agencies, ACER benefits from a Union subsidy set aside specifically in the general budget of the European Union. As explained in Section 2, ACER has been tasked with additional functions since its establishment. These tasks have been accompanied with additional staff. However, ACER is also subject to the programmed reduction of staff in decentralised agencies by 5% over a period of 5 year set out in the Commission's communication on *"Programming of human and financial resources for decentralised agencies 2014-2020"*[201]. It is clear that any additional tasks for ACER as envisaged in the proposed initiatives will further tighten its financing and staffing and will require further resources.

Another set of shortcomings can be tracked to insufficient participation of DSOs within the institutional framework. Under the energy transition, a traditional top-down, centralised electricity distribution system is being outpaced by more decentralised generation and consumption. The integration of a significant share of variable solar and wind generation capacity connected directly to distribution networks create new requirements and possibilities for DSOs, who will have to deal with increased capacity while maintaining quality of service and minimizing network costs. In addition, the electrification of sectors such as transport and heating will introduce new loads in distribution networks and will require a more active operation and better planning.

The problem is aggravated by the fact that specific requirements on TSO – DSO cooperation as set forth in the different Network Codes and Guidelines, and new challenges that TSOs and DSOs are jointly facing, will require greater coordination between system operators.

For the time being, no provision at all is made for the formal integration of DSOs into the EU institutional decision making. However, from a policy perspective a cohesive and consistent participation of DSOs in the EU institutional framework is required. Future electricity system will require a more coordinated approach of TSOs and DSOs on issues of mutual concern. Regarding network codes, DSOs will need to display a common approach, as many of the envisaged network codes are directly or indirectly concern distribution grids.

As set out in the evaluation report[202], while the principles of the Third Package achieved its main purposes, new developments in electricity markets led to significant changes in the market functioning in the last five years. The existing rules defining the institutional framework are not fully adapted to deal with the recent changes in electricity markets effectively. Therefore, it is reasonable to update these rules so that they may be able to cope with the reality of today's energy system.

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201 Communication from the Commission to the European Parliament and the Council, COM(2013)519 final of 10.07.2013.

202 Evaluation Report covering the evaluation of the EU's regulatory framework for electricity market design and consumer protection in the fields of electricity and gas and evaluation of the EU rules on measures to safeguard security of electricity supply and infrastructure investment (Directive 2005/89).

The institutional framework currently applicable to the internal energy market as set out in the Third Package is based on the complementarity of regulation at national and EU-wide level. In view of the developments since the adoption of the Third Package as described in the evaluation report, the institutional framework, especially as regards cooperation of NRAs at regional level, will need to be adapted to ensure the oversight of entities with regional relevance. Moreover, as the European energy markets are more and more integrated, it is crucial to ensure that ACER can function as swiftly and as efficiently as possible. In addition, the implementation of the Third Package has highlighted areas with room for improvement concerning the framework applicable to ACER and the ENTSOs.

3.4.3. *Presentation of the options*

Option 0: Business as usual

The business as usual (BAU) option does not foresee new, additional measures to adapt or improve the institutional framework. Apart from the continued implementation of the Third Package and the implementation of network codes and guidelines, this option would leave the EU institutional framework unchanged, meaning that it would continue to be primarily based on a close complementarity of regulation at national and EU-wide level.

The challenges arising through the changes to and the stronger integration of the European energy markets could not be tackled and regulatory gaps arising from the adoption and implementation of network codes and guidelines would also remain unaddressed. This could potentially lead to delays in their implementation and ultimately act as a barrier to achieving the electricity EU target model.

The BAU option would maintain the limitation of ACER's decision-making powers and would not remedy the risks arising from the fragmented national regulatory approach. NRAs and ACER would continue to face difficulties fulfilling their tasks that have relevance at regional and EU level.

The business as usual option would leave ACER's current internal decision-making unchanged. This would mean that where the favourable opinion of the Board of Regulators is necessary, this would have to be reached with two-thirds majority facing the risk of delays or lack of agreement.

Under this option the process of developing network codes would remain unchanged. This would allow ENTSO-E to continue playing a very strong role in setting European market rules, going beyond of that providing technical expertise. This option would neither improve the rules on ENTSO-E's transparency and independence nor the rules of ACER's oversight of ENTSO-E. The progress concerning ENTSO-E's transparency would depend on the voluntary initiative of the association. The criticisms to the existence of conflicts of interest regarding the roles of ENTSO-E, particularly as regards the development of network codes, would not be addressed.

Under the Option business as usual, despite having been assigned additional responsibilities since its establishment, ACER would still be constrained by the current regulatory framework as regards the regulatory oversight of new entities and functions performing at regional or EU level.

This Option would maintain the current framework for the functioning of ACER's Board of Appeal. This means that its independent functioning and financing would continue to be highly vulnerable.

The BAU also foresees no integration of DSOs into the institutional decision-making setting as explained under the Section dealing with the shortcomings of current legislation. It is true that in 2015, with the support of the Commission, the four European DSO associations and ENTSO-E established a cooperation platform[203] between TSOs and DSOs at EU level. This cooperation has the objective to work on issues of mutual DSO-TSO concern such as coordinated access to resources, regulatory stability, grid visibility and grid data. However, this cooperation remains purely voluntary in nature with no formal expression in the wider EU decision making setting or ACER.

In sum, European DSOs collaborate through the existing DSO associations but without any legal status at EU institutional level. There is no formal participation in drafting or amending of network codes and guidelines.

Option 0+: Non-regulatory approach

Under this option a "stronger enforcement" approach and voluntary collaboration as a non-legislative measure were considered without foreseeing any new, additional measures to adapt the institutional framework. Improved enforcement of existing legislation would entail the continued implementation of the Third Package and the implementation of network codes and guidelines – as described under option business as usual – combined with stronger enforcement. However, stronger enforcement would not provide any improvement to the current institutional framework as it is already fully implementing the existing legal framework.

Collaboration in the current institutional framework is based on legal obligation. While voluntary cooperation might be possible in areas not covered under the Thrid Energy Package, it would require establishing parallel structures and additional resources without significantly improving the functioning of the current regulatory framework. Therefore, voluntary collaboration is not considered a valid option.

Therefore, the Option 0+ would leave the EU institutional framework unchanged, meaning that it would continue to be based, primarily, on a close complementarity of regulation at national and EU-wide levels. Furthermore, any improvement compared to the current situation would have to stem from voluntary initiatives of the involved bodies. In addition, this option could not provide the necessary solutions arising from the changing market reality as described in this impact assessment. Therefore, this option is discarded as not valuable in providing solutions for the described shortcomings and overall developments.

[203] ENTSO-E, CEDEC, GEODE, EDSO, EURELECTRIC (2015), "*General Guidelines for reinforcing the cooperation between TSOs and DSOs*" (http://www.eurelectric.org/media/237587/1109_entso-e_pp_tso-dso_web-2015-030-0569-01-e.pdf)

Option 1: Upgrade the EU institutional framework

Option 1 foresees adapting the EU institutional framework to the new realities of the electricity system[204] and to the resulting need for additional regional cooperation and to address the existing and anticipated regulatory gaps in the energy market, providing thereby for flexibility by a combination of bottom-up and top-down approaches. Option 1 would adapt the institutional framework set out in the Third Package to address the regulatory gaps materialising through the implementation of the Third Package and resulting from the adoption and implementation of network codes and guidelines. It would also adapt the institutional framework to the new realities of the electricity system and to the resulting need for additional regional cooperation.

As regards ACER's decision-making, Option 1 would largely entail reinforcing its powers to carry out regulatory functions at EU level. In addition, in order to address the existing regulatory gap as regards NRAs' regulatory functions at regional level, the policy initiatives under this option would set out a flexible regional regulatory framework to enhance the regional coordination and decision-making of NRAs. This Option would introduce a system of coordinated regional decisions and oversight for certain topics by NRAs of the region (e.g. ROCs and others deriving from the proposed market design initiatives) and would give ACER a role for safeguarding the EU-interest.

Option 1, while giving ACER additional powers, would also ensure that the Agency can swiftly and effectively reach these decisions in its Board of Regulators. To enable NRAs to take decisions without delay in the BoR, this Option would adapt the BoR internal voting rights. Option 1 also reflects on the necessity to ensure that all (existing and proposed) ACER decisions are subject to appeal and that the ACER Board of Appeal can act fully independently and effectively through adjusting its financing and internal rules.

Further, concerning ACER's competences, Option 1 entails strengthening ACER's role in the development of network codes, particularly as regards giving the Agency more responsibility in elaborating and submitting the final draft of the network code to the Commission, while maintaining ENTSO-E's relevant role as a technical expert. This Option would also involve strengthening ACER's oversight over ENTSO-E. In addition, Option 1 would effectively distinguish ENTSO-E's statutory mandate from defending its member companies' interests by setting out a clear European mandate in the legislation and ensuring more transparency in its decision-making processes.

Under this Option, ACER would receive additional competence to oversee new entities and functions which are not currently subject to regulatory oversight at EU level. This is the case for power exchanges operating in their cross-border functions; they play a crucial role in coupled European electricity markets and perform functions that have characteristics of a natural monopoly. Depending on the type of entity or function and their geographical scope, this Option would either introduce NRAs' coordinated regional oversight with support and monitoring by ACER or ACER oversight with NRAs' contribution.

[204] As further detailed in Section 1 of the main body of this impact assessment.

As described in this Section, Option 1 would give ACER additional tasks and powers while acknowledging that appropriate financing and staffing is key for ACER to perform its role. Therefore, Option 1 foresees additional sources of financing which would be possible either by increasing the EU financing or by introducing co-financing, complementary to the Union financing the sector ACER is supervising[205].

This Option would also include a formal place for DSOs to be represented at EU level, in line with an increase in their formal market responsibilities and role as has been mentioned above. The establishment of an EU DSO entity will enable the development of new policies which can positively affect the cost efficient integration of distributed energy resources including RES E, and which will reinforce the representation and participation of EU DSOs at an institutional European level.

Option 1 thus envisages the establishment of an EU DSO entity for electricity with an efficient working structure. European DSOs will provide experts based on calls for proposals issued by the EU-DSO. European DSOs will participate in financing the EU-DSO entity through a Supporting Board based on the existing EU DSO associations (Eurelectric, EDSO, CEDEC, GEODE).

Tasks of the EU DSO will include:

- Drafting network codes/guidelines following the existing procedures;
- Monitor the implementation of network codes on areas which concern DSOs;
- Deliver expert opinions as requested by the Commission;
- Cooperate with ENTSO-E on issues of mutual concern, such as data management, balancing, planning, congestion, etc.

The EU DSO entity will also work on areas such as DSO/TSO cooperation, integration of RES, deployment of smart grids, demand response, digitalisation and cybersecurity.

Option 2: Restructure the EU institutional framework

Option 2 would significantly restructure the institutional framework, going beyond addressing the regulatory gaps identified above and moving towards more centralised institutional structures with additional powers and responsibilities at European level, particularly as regards the role of ACER and ENTSO-E.

Concerning ACER's powers, Option 2 would extend ACER's decision-making powers to all regulatory issues with cross-border trade relevance. This would result in ACER taking

[205] The Commission’s aim for decentralised agencies is to eliminate EU and national budgetary contributions and wholly finance them by the sector they supervise, see the Mission letter of Commissioner Hill of 1 November 2014. In this sense ACER could be co-financed through the sector it is supervising. In the light of ACER’s cruacial role in delivering on the common EU objectives and in particular in protecting the Eurpean energy markets from fraud, the functioning of ACER could be co-financed with contributions from market participants and/or public bodies benefitting from ACER’s activities. This would contribute to guaranteeing ACER's full autonomy and independence.

over most NRA responsibilities directly or indirectly related to cross-border and EU-level issues. This Option would further give the ACER Director the power to become the main decision-making instance in the Agency, as opposed to the BoR, possibly with veto powers from the Board of Regulators on certain measures.

As regards ACER's competences, Option 2 would entail a direct oversight over ENTSO-E and over other entities fulfilling EU level or regional functions, giving ACER the power to take binding decisions.

In order for ACER to perform its role under Option 2, it would require a significant reinforcement of ACER's budget and staff as this would make a strong concentration of experts in ACER necessary. Therefore, this option would entail – as foreseen under Option 1 – reinforcing EU funding and the possibility to introduce in addition financing through market players and/or public bodies. As Option 2 would give ACER such strong powers it would also entail a significant reinforcement of the structural set-up of the Board of Appeal to ensure that the appeal mechanism can function independently and effectively because it would potentially face a significantly higher number of appeals due to the increasing number of direct ACER decisions foreseen under this Option.

As regards to ENTSO-E's competences, this option would require a formal separation of ENTSO-E from its members' interest. It would strengthen the independence of ENTSO-E by introducing a European level decision-making body who would have powers to decide on proposals and initiatives without requiring prior TSOs' approval.

With regards to the role of DSOs, the measures included under Option 1 would apply to Option 2 as well. The move to an EU regulator with full powers would however mean that ACER would have to also carry out the oversight of, and entertain relations with, DSOs in a way that is now done at Member State level.

Table 2: Detailed overview of the measures proposed under the three options

ISSUE	Option 0: Business as usual	Option 1: Ugrade EU insitutional framework to address regulatory gaps	Option 2: Restructur EU institutional framework
ACER decision-making	Limited, through recommendations and opinions Most regulatory decisions with BoR favourable opinion ACER Director manages ACER and tables proposals for BoR favourable opinion	ACER decisions with BoR favourable opinion, also replacing Guideline implementing "all NRA" decisions at EU and regional levels Framework of regional NRA decision-making with ACER oversight (complementary role to safeguard EU interest)	ACER decision without BoR involvement, mainly by ACER Director
BoR decision-making	2/3rds majority for the most of ACER decisions	Simple majority for most of ACER decisions	2/3rds majority for ACER decisions in a limited instances
Board of Appeal	Independent body for all appeal cases Some of its costs are envisaged in the ACER budget	Independent body for all appeal cases with strengthend framework and separate budget line in the ACER budget	Independent body for all appeal cases with strengthend line of financing and framework
ACER Financing	Community/EU-funding (separate budget line) Possibility for ACER to collect fees for individual decisions	Need for increased financing (possibly through increased EU-funding and possibly co-financing by contributions by market participants and/or national public authorities	Need for significantly increased financing (possibly through increased EU-funding and possibly co-financing by contributions by market participants and/or national public authorities
Network Code development process	Based on ACER's framework guideline ENTSO-E drafts network code (strong role and influence), ACER provides opinion and recommendation to the Commission.	Based on ACER's framework guideline ENTSO-E drafts network code guided by a standing stakeholder body and broad general stakeholder involvement, ACER consolidates the network code and submites the final product to the Commission	Based on ACER's framework guideline ENTSO-E drafts network code with the involvement of standing stakeholder body, ACER consolidates the network code (ACER internal decision without Board of Regulators' favourable opinion) and submites the final product to the Commission
Oversight of ENTSO-E	Limited ACER oversight of ENTSO-E	Strenghtened ACER oversight of ENTSO-E	Strenghtened ACER oversight of ENTSO-

			E
Oversight of new entities	None or limited regulatory oversight (limited rules in network codes and guidelines)	Strenghtened regulatory oversight by NRAs and ACER	ACER direct oversight
ENTSO-E's mission and transparency	Lack of clear European mission and voluntary transparency rules	Codified clear European mission and transparency obligations on its decision-making	Formal separation from its members' interests and creation of a decision-making body
DSO	European DSOs collaborate through the existing DSO associations but without any legal status at EU institutional level. There is no formal participation in drafting or amending of network codes and guidelines	Establishment of an EU DSO entity for electricity with an efficient working structure; European DSOs will provide experts based on calls for proposals issued by the EU-DSO.	Same as Option 1, plus an increased role for coordination and oversight on the part of ACER

Source: European Commission

3.4.4. *Comparison of the options*

As stated above, the goal of the proposed initiatives is to adapt the institutional framework to the reality of integrated regional markets. In this regard, as it will be further illustrated below, Option 0, the business as usual option, would not contribute towards achieving this objective and in some instances it may even be detrimental, since the institutional framework needs to be able to provide tools for the different parties (ACER, NRAs, ENTSO-E) to address the challenges arising from the integration of the markets.

Options 1 and 2 can capture the challenges and potential opportunities, but the efficiency, effectiveness and economic impact of these options can vary significantly.

Table 3: Qualitative comparison of Options in terms of their effectiveness, efficiency and coherence of responding to specific criteria

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

Source: European Commission.

The assumptions in this table are based on the feedback received from stakeholders in their response to the public consultation and from additional submissions from ACER.

Table 4: Qualitative estimate of the economic impact of the Options

	Economic Impact		
	Internal Market for electricity	**Transparency and non-discrimination**	**Administrative impact and implementation costs**
Option 0: Business as usual	0/+	-	0
Option 1: Upgrading EU institutional framework	+	+	0/-
Option 2: Restructuring EU institutional framework	++	++	--

Source: European Commission

The assumptions in this table are based on the feedback received from stakeholders in their response to the public consultation and from estimations concerning the resources of ACER and ENTSO-E.

In summary, Option 0 – business as usual – will fall short in providing for an institutional framework that can underpin the integration of the internal electricity market in a timely manner.

Option 1, addressing regulatory gaps by upgrading the EU institutional framework would be, according to the assessment of the options above, the most appropriate measure for establishing an EU institutional framework that reflects and complements the increasingly integrated and regional dimension of the electricity market. This option is favoured by most of the stakeholders[206]. It represents a flexible approach combining bottom-up initiatives and top-down steering of the regulatory oversight, respecting the principle of subsidiarity.

Option 2, significantly restructuring the EU institutional framework, while having advantages in terms of requiring less coordination and being as efficient as Option 1, it has the clear disadvantage of requiring significant changes to established institutional practices and processes and of having the greatest economic impact. Some of the solutions proposed under Option 2, such as those involving the extension and shifting of decision-making powers and responsibilities, would raise severe opposition from stakeholders. That would be for example the case for ACER and the transfer of decision-

[206] 70% of stakeholders responding to the relevant questions of the Commission's public consultation on a new market design were in favour of strengthening ACER's institutional role, e.g. some mentioning that it may be efficient to enable ACER to take decisions on cross-border issues where EU network codes/guidelines require decisions to be taken by all national regulatory authorities. Further, many stakeholders asked for improving ENTSO-E's independence from its members' commercial interest.

making powers from NRAs[207]. In summary, Option 2 did not receive support from stakeholders.

The Commission Services are of the view that Option 1 "upgrading the EU institutional framework " is currently the most appropriate approach to achieve the main objective pursued i.e., adapt the institutional framework and ACER's decision powers and internal decision-making to the reality of integrated regional markets.

It is also relevant to note, that as the institutional framework for the European energy market design initiative, the proposals discussed above in the options will be accompanied by some further changes originating from the need to adapt ACER's funding Regulation to the Common Approach on EU decentralised agencies[208] and to incorporate some minor improvements to streamline the institutional framework established in the Third Package.

Further, as the Third Package establishes an identical institutional framework for electricity and for gas[209], changes to this system will be also applied to the gas sector where relevant and reasonable to ensure that rules and processes are identical for the two sectors in the future.

3.4.5. *Budgetary implications of improved ACER staffing*

This Section provides an estimate of budgetary implications from adjusting ACER staffing to adequately meet new tasks and responsibilities envisaged under the preferred option (Option 1) as well as under the highly ambitious Option 2.

As per the Agency's draft 2017 Work Programme, ACER employed on 31.12.2015 a total of 54 Temporary Agents, of which 39 at AD level and 15 at AST level. The Agency further employed an additional 20 Contract Agents and 6 SNE, raising the total ACER headcount to 80.

It should be noted that the European Commission, in its latest opinion on the ACER Work Programme[210] did not agree to grant additional staff under the 2017 budget, judging that current staff figures are adequate to meet current tasks and suggesting that ACER shifts resources internally to meet priority objectives.

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[207] Most of the Member States responding to the relevant questions of the Commission's public consultation on a new market design favored preserving the *status quo* as regards the institutional framework.

[208] The Common Approach on EU decentralised agencies agreed in July 2012 by the European Parliament, the Council and the Commission defines a more coherent and efficient framework for the functioning of agencies. Although legally non-binding, it serves as a political blueprint not only guiding future horizontal initiatives but also in reforming existing, individual EU agencies. Most importantly, the implementation of the Common Approach requires the adaptation of the founding acts of existing agencies, based on case by case analysis.

[209] For example, the Third Package, in the Gas Regulation established the European Network for Transmission System Operators for Gas (Art. 5).

[210] Commission Opinion on the draft Work Programme of the Agency for the Cooperation of Energy Regulators, C(2016)3826 of 24.6.2016

In line with additional tasks foreseen under Option 1 and Option 2, ACER staffing resources should however be adapted.

The tables below show the financial implications of Option 1 and Option 2 for extra staff. The average cost per headcount is based on the latest DG BUDGET declared average cost[211]: for a Temporary Agent, total average costs including "bailage" costs (real estate expenses, furniture, IT, etc.), stand at EUR 134.000 per year per individual.

Table 5: ACER staff: budgetary implications under Option 1

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

Source: Own calculation based on DG BUDG figures

[211] Circular note of DG BUDGET to RUF/2015/34 of 09.12.15

Table 6: ACER staff: budgetary implications under Option 2

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

Source: Own calculation based on DG BUDG figures

These calculations are only approximate as they cannot take into account the grade level of future recruited staff or the exact breakdown of future tasks. This is particularly true for Option 2, which would entail a complete overhaul of the Agency and the appropriation of full regulatory competences for 28 markets.

3.4.6. *Subsidiarity*

The current institutional framework for energy in the Union is based on the complementarity of regulation at national and EU level. The Third Package mandated the designation by Member States of national regulatory authorities and required that they guarantee their independence and ensure that they exercise their role and powers impartially and transparently at national level. The Third Package also created ACER and ENTSO-E in order to enhance the coordination of national energy regulators and elecricity TSOs at EU level.

The implementation of the Third Package through the adoption of Commission implementing regulations has led to the creation of new entities and functions which have changed the regulatory landscape. Some of these entities/functions have EU-wide relevance (e.g., the market coupling operator function in the electricity sector) whereas others have regional relevance (e.g., the regional security coordinators in the electricity sector, capacity allocation platforms in the gas sector).

Moreover, the electricity markets have become more integrated due to increasing cross-border electricity trade and more physical interconnections in the European electricity grid. This, together with progressively higher shares of decentralized and variable renewable energy sources, have rendered the national electricity systems much more interdependent than in the past.

Whereas the institutional framework envisaged in the Third Package has undoubtedly been successful, the unprecedented changes described above have highlighted the existence of regulatory gaps. These gaps appear, for example, where the creation of the entities/functions with EU-wide or regional relevance has not been accompanied with the necessary tools to equip ACER with powers to exercise regulatory oversight over them, despite the fact that they will be carrying out monopoly or critical functions for the internal energy market at EU or regional level. Other gaps relate to the lack of regulation ensuring the consistent implementation of governance principles across regions or to the lack of clarity concerning the roles and responsibilities of national regulatory authorities, ACER and ENTSO-E following the adoption of Commission implementing regulations.

It is therefore necessary to adapt the institutional framework in the Third Package to meet this new reality and provide a basis for realizing the full potential of the internal energy market. This is why the roles of NRAs, ACER, and ENTSO-E need to further evolve, clarifying their powers and responsibilities over relevant geographical areas. In addition, it will be necessary to adapt the institutional framework to the changes in EU energy legislation stemming from the proposed initiatives.

Proportionality

Option 1 would be in line with the proportionality principle given that it aims at clearly defining the roles, powers and responsibilities of the main actors (NRAs, ACER, ENTSO-E) so that they are adapted to the new realities of the electricity markets and to the need for more regional cooperation. More specifically:

- The improvements to the ACER framework under this option do not aim at replacing national regulatory authorities but rather at complementing their role as regards issues which have regional/EU-wide relevance. The scope of ACER's responsibilities will continue to be limited to cross-border relevant issues.
- The improvements concerning the regulatory oversight at regional level aim at addressing the regulatory gap that has arisen with the implementation of the Third Package through the adoption of Commission implementing regulations.
- The amendments of the ENTSO-E framework under this option principally aim at improving and clarifying its mandate to ensure its European character and to introduce more transparency in its internal decision-making processes.
- The improvements to the process for developing Commission implementing regulations (network codes and guidelines) aim at addressing some of the shortcomings identified in the past years.
- The establishment of an EU DSO entity will support EU policies and RES integration in the electricity system, will support the swift implementation of network codes and guidelines, and enhance cooperation between TSOs and DSOs.

3.4.7. _Stakeholders' opinions_

This Section provides a more detailed summary of the views expressed by stakeholders regarding the adaptation of the institutional framework in the European Electricity Regulatory Forum and in response to the Commission public consultation on a new market design.

The 29th meeting of the European Electricity Regulatory Forum of 9 October 2015 underlined, as a conclusion, *"the need for analyzing and further elaborating the roles, tasks, responsibilities and consider possible governance structures of ACER and ENTSO-E"* and stressed *"the need to observe and consider possible governance structures for other bodies, including DSOs and power exchanges, and for NEMO cooperation."*

As regards enhancing ACER's institutional role, in response to the Commission public consultation on a new market design, 70% of all stakeholders who answered the questions on ACER wanted to increase the powers or tasks of ACER (notably as regards oversight of ENTSO-E). 30% supported to keep the *status quo*. Only a limited number of respondents (5%) mentioned missing independence of ACER as a problem. In general, views differed between Member States and NRAs on the one hand (rather for preserving *status quo*) and other stakeholders (rather in favour of strengthening powers at regional/EU level).

Within the development of a robust regulatory framework for the entities performing monopoly or near-monopoly functions at EU or regional level, ACER called for the power to exercise regulatory oversight over such entities[212]. With regard to regional cooperation, which should be promoted by the NRAs, ACER can support NRAs' actions and should be responsible for promoting and monitoring the consistency of regional implementation and of the activities of entities performing monopoly or near-monopoly activities at regional level.

As regards ENTSO-E, 38% of the respondents to the public consultation on a new market design did not have or did not express any opinion or preference regarding the possible strengthening of ENTSO-E. Looking at the respondents having an opinion on this topic, 59 % of the respondents were in favour of not to strengthen ENTSO-E while 41% asked for a stronger ENTSO-E.

As regards power exchanges, 63% of the respondents to the consultation answering this specific question were of the view that there is a need for enhanced regulatory oversight of power exchanges.

As regards the process for development of Commission implementing regulations in the form of network codes and guidelines, some of the respondents to the consultation mentioned the existence of a possible conflict of interest in ENTSO-E’s role – being at the same time an association called to represent the public interest, involved e.g. in

[212] ACER's position on the regulatory oversight of (new) entities performing monopoly or near-monopoly functions at EU-wide or regional level.

network code drafting, and a lobby organisation with own commercial interests – and asked for measures to address this conflict. Some stakeholders suggested that the process for developing network codes should be revisited in order to provide a greater a balance of interests. Some submissions advocated for including DSOs and stakeholders in the network code drafting process.

As regards DSOs, the establishment of an independent EU-level DSO entity has been welcomed by stakeholders on multiple occasions. In particular, attention is drawn to the Conclusions of the 31st Energy Regulators Forum, whereby: *"The Forum takes note of the announcement from the Commission of the establishment of an EU- level DSO entity that can serve to provide expertise in advancing the EU market. The Forum invites the Commission, in the design of any entity, to ensure a balanced representation of DSOs and maximum independence and neutrality".* Equally, regulators (ACER and CEER) suggested considering whether DSOs should be encouraged to establish a single body through which they can more efficiently participate in the process of new electricity market design.