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COVER NOTE

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To:	Mr Jeppe TRANHOLM-MIKKELSEN, Secretary-General of the Council of the European Union
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Subject:	COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT Accompanying the document Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast) Proposal for a Regulation of the European Parliament and of the Council on the electricity market (recast) Proposal for a Regulation of the European Parliament and of the Council establishing a European Union Agency for the Cooperation of Energy Regulators (recast) Proposal for a Regulation of the European Parliament and of the Council on risk preparedness in the electricity sector

Delegations will find attached document SWD(2016) 410 final - PART 2/5.

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PART 2/5

COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT

Accompanying the document

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

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

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

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

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ANNEXES

Annex I: Procedural information

Lead DG: DG Energy

Agenda planning/Work Programme references:

- AP 2016/ENER/007 (Initiative to improve the electricity market design)
- AP 2016/ENER/026 (Initiative to improve the security of electricity supply)

Publication of Inception Impact Assessment:

- October 2015 (Initiative to improve the electricity market design)
- October 2015 (Initiative to improve the security of electricity supply)

No feedback was received on the Inception Impact Assessments

Inter-service group:

An Inter-service group meeting was used comprising the Legal Service, the Secretariat-general, DG Budget, DG Agriculture and Rural development, DG Climate action, DG Communications Networks, Content and Technology, DG Competition, DG Economic and Financial Affairs, DG Employment, Social affairs and Inclusion, DG Energy, DG Environment, DG Financial stability, Financial services and Capital markets, DG Internal market, Industry, Entrepreneurship and SMEs, the Joint Research Centre, DG Justice and Consumers, DG Mobility and Transport, DG Regional and urban development, DG Research and innovation, DG Taxation and Customs Union.

Not all Directorate-generals did participate in each ISG meeting

Meetings of this ISG were held on: 28 October 2015, 25 April 2016, 20 June 2016 and 8 July 2016

Consultation of the RSB

The impact assessment was submitted to the RSB on 20 July 2016. On 14 September 2016, the impact assessment was discussed with the RSB. On 16 of September 2016 the RSB issued it opinion, which was negative. It requested to receive a revised draft of the IA report addressing its recommendations whilst briefly explaining what changes have been made compared to the earlier draft. A draft impact assessment was resubmitted on 17 October 2016. A positive RSB Opinion, with reservations, was issued on 7 November 2016?

The opinions and the changes made in response are summarised in the tables below.

Comments made by RSB in first Opinion of 16 September 2016	Modifications made in reaction to comments RSB
Issues cross cutting to other impact assessments	
This IA and the IA on the revision of the renewables directive need a coherent analysis of renewable electricity support schemes. They need to reconcile different expectations of what the market will deliver in terms of the share of renewable electricity and of the participation of prosumers. Given uncertainty on these issues, both IAs should incorporate the same range of possible outcomes in their analysis	An explicit vision of the EU electricity market has been incorporated in section 1.1.1.4. This vision includes a section on the connection with the share of RES E and prosumers.
The IA should clarify and explain the content and assumptions of the baseline scenario in relation to the other parallel initiatives	A dedicated section was included in Annex IV clarifying all points raised concerning the baseline, REF2016 and EUCO27. The baseline description in 5.1.2, 5.2.2, 6.1.1.2 and 6.1.1.4 was improved and references were made to its more detailed description in the Annex.
Issues specific to the present impact assessment	
The IA report is too long and complex to make it helpful in informing political decisions. The Board recommends that this report begin with a concise, plain-language abstract of approximately 10-15 pages. This abstract should summarise the key elements of the IA and identify the main policy trade-offs	A plain-language abstract has been added at the beginning of the document.
The report should present a clear vision for the EU electricity market in 2030 and beyond with a distinction between immediate challenges and longer term developments. This vision needs to be coherent with EU policies on competition, climate and energy. It also needs to be consistent with the parallel initiatives, notably the revision of the RES Directive. In particular, this applies to the assumptions and expectations on what the new electricity market design could deliver on its own and whether the renewable target requires complementary market intervention.	An explicit vision of the EU electricity market has been incorporated in section 1.1.1.4 covering issues mentioned. A detailed section on in RES E in connected with the MDI is contained in a text box in section 6.2.6.3. Another box is located in Section 2.1.3. Further clarifications have been added in section 1.2.1 on interlinkages with RED II.
Based on a common (with other parallel initiatives) baseline scenario, the report should prioritise the issues to be addressed, present an appropriate sequencing and strengthen the treatment of subsidiarity considerations such as for action related to energy poverty and distribution system operators.	A dedicated section was introduced in Annex IV clarifying all points raised concerning the baseline, REF2016 and EUCO27. The baseline description in 5.1.2, 5.2.2, 6.1.1.2 and 6.1.1.4 was improved and references were made to its more detailed description in the Annex.

Comments made by RSB in first Opinion of 16 September 2016	Modifications made in reaction to comments RSB
	A dedicated section on sequencing was introduced as section 7.5.3 Regarding the treatment of subsidiarity for actions related to energy poverty, please see sections 5.4.4; and 5.4.5. The report assesses the options with regards to subsidiarity. It argues that measures in Option 1 are proportionate and in line with the subsidiarity principle while measures in Option 2 entail significant costs and may be better carried out by national authorities.
When assessing the impacts of the different options, the report should indicate whether and how the models of "energy only markets" will coexist with capacity mechanisms and assess the risks of an uncoordinated introduction of capacity remuneration mechanisms across the EU. The impact analysis should also report on the effectiveness of the options to deliver the adequate investment and price responses.	On how the models of "energy only markets" will coexist with CMs, clarifications have been introduced in section 2.2.2. Section 6.2.6 now includes a sub-section on investments, discussing all relevant issues.
Main recommendations for improvements	
The analysis of support schemes for renewable electricity should be consistent across this impact assessment and the one covering renewable energy sources. The reports should clarify what support schemes will be needed, and whether these are needed only in case the market fails to deliver the 2030 EU target of at least 27% of RES in final energy consumption, or will be used to promote certain types of renewable energy.	An explicit vision of the EU electricity market has been incorporated in section 1.1.1.4. This includes a vision on <u>whether</u> outside-the- market measures to support for RES E are needed up to 2030. The question <u>what type</u> of out-of-market support mechanisms are needed falls within the remit of the RED II IA. A dedicated section was included in Annex IV clarifying all points raised concerning the baseline. Via the definition of the baseline, the impact assessment for the MDI and RED II are fully compatible, including as regards the assessment of support schemes.
The IA should take into account the tendering procedure envisaged for procuring support for renewable energy producers and assess its impact on the electricity market.	An explicit vision of the EU electricity market has been incorporated in section 1.1.1.4. This includes a vision on <u>whether</u> outside-the- market measures to support for RES E are needed. A detailed section on in RES E in connected with the MDI is contained in a text box in section 6.2.6.3. Further clarifications have been added in section 1.2.1 on interlinkages with RED II.

Comments made by RSB in first Opinion of 16 September 2016	Modifications made in reaction to comments RSB
In addition, even though the report does not present a blueprint for a capacity remuneration mechanism (as it is in the remit of the state-aid guidelines/EU competition policy), it should analyse possible detrimental effects of such mechanisms being introduced in the EU in an uncoordinated fashion. In particular, the IA should examine distortions to investment incentives and price setting mechanisms.	The clarification in Annex IV as regards the baseline explains how, the impact assessments for the MDI and RES E are fully compatible, including as regards to the tendering procedure (see section on current market arrangements in Annex IV). Text adapted in section 2.2.2 and included a reference to forthcoming report by DG Competition.
The expected involvement of consumers and prosumers in supplying electricity and managing its demand has to be consistent across the two impact assessments. The analysis should integrate the effects of potentially more volatile electricity prices and high fixed network costs on prosumer involvement and on the long-term risk that these might disconnect from the network as local storage technology evolves.	An explicit vision of the EU electricity market has been incorporated in section 1.1.1.4. This includes a vision on prosumers and the risk of disconnection, which is further developed in a text box in Section 6.1.4.2. Also the RED II IA has been adjusted.
In devising the options, the report should be proportionate to the importance of the problems/objectives and realistic in assessing what can be achieved. For instance, options linked to the issue of energy poverty (being part of the social policy) should be built around increasing transparency and peer pressure among Member States rather than the single market motive.	See section 2.4.1 and section 5.4.4. The report clarifies the main objective of the measures linked to energy poverty (i.e. description of the term 'energy poverty' and measurement of energy poverty), which already apply to Member States (Member States should address energy poverty where it is identified). Better monitoring of energy poverty across the EU will, on one hand, help Member States to be more alert about the number of households falling into energy poverty, and on the other hand, peer pressure encourages Member States to put in place measures to reduce energy poverty.
The baseline scenario should be clarified, including the link with the 2016 reference scenario and underlying assumptions	A dedicated section was included in Annex IV clarifying all points raised concerning the baseline, REF2016 and EUCO27.
Some more technical comments have been transmitted directly to the author DG and are expected to be incorporated into the final version of the impact assessment report	All technical comments have been addressed.

Comments made by RSB in first Opinion of 16 September 2016	Modifications made in reaction to comments RSB
The IA report needs to be more reader-friendly and helpful for decision-making. The report should contain a 10-15 page abstract that succinctly presents the main elements of the analysis, the policy trade-offs and the conclusions. The main text should be streamlined to contain the crucial elements of the analysis in the main part of the report	A reader friendly abstract that succinctly presents the main elements of the analysis, the policy trade-offs and the conclusions has been added to the main text of the IA.

Comments made by RSB in second Opinion on 7 November 2016	Modifications made in reaction to comments RSB
Opinion RSB on resubmission	
Restoring price signals for investments is one crucial element of the revised market design. The report is clearer on its view that undistorted markets deliver the right price signals for investment. The report should more convincingly explain how adequate pricing could be achieved in the presence of national capacity markets and subsidies for renewables which might exacerbate excess capacity in the market. The report should assess the risk of persistent low electricity wholesale prices and associated consequences for the effectiveness of the initiative. What would be the effects for investment, demand response, elimination of subsidies, and consumer benefits?	Reference is made to the new Box 9 underneath Section 6.4.6 for further explanations, which was added following the RSB comments.
Further recommendations for improvements	
Internal coherence and risks: The analysis in the report demonstrates that the vision for the EU electricity market in 2030 and beyond relies on the implementation of many different policies and assumptions, and is subject to numerous risks. The narrative of the report should more clearly reflect these risks. The report should propose modalities to review assumptions and monitor implementation at intermediate stages. The text of the report should reflect the trade-off between restoring the EU internal energy market in its pure form and government intervention to support renewable energy sources and to maintain security of supply.	Text has been added to Sections 8.1 and 8.2.2 with regard to the reviewing of assumptions and monitoring of implementation. The 2030 RES E objectives are part of the base-line of the analyses. Trade-offs between government interventions in support of RES E are investigated in the REDII impact assessment. However, in the present report, it has been rendered more clearly what elements of the RED II initiative are important to the impacts of the present initiative. See in this regard Section 1.1.1, 1.2.1, Box 7 under section 6.2.6.3, Box 9 under Section 6.4.6 and Annex IV. It is noted that improving market functioning reduces the need for government intervention with regard to both RES E (See Section 1.1.1.4, Box 7 below section 6.2.6.3 and section 7.5.1) and resource adequacy (See section 6.2.2.1, Section 6.2.6.3 and Section 7.5.1).
Impact analysis: The vision of an energy Union places citizens at its core. The report should therefore better address the risks and benefits to consumers, especially with regard to expected higher price variability. It should discuss not just possible long run benefits, but also costs (including switching	The risks of greater price variability have been introduced in two new text boxes in Section 5.1.4.3 (Box 4) of the main impact assessment document, and in Section 3.1.5 of the Annexes to the Impact Assessment. These specifically address the benefits and risks of dynamic electricity pricing

Comments made by RSB in second Opinion on 7 November 2016	Modifications made in reaction to comments RSB
fees) in the short and medium term. In the same vein, the report should examine the impact of the policy on various groups of consumers	contracts, which are a frequent concern of consumer groups. The impacts of the measures in Problem Area IV (Retail Markets) on different groups of consumers have been addressed in a text box in Section 6.4.3.2 of the Impact Assessment Report (Box 8) and text boxes in Sections 7.1.5, 7.2.5, 7.3.5, 7.4.6, 7.5.5, and 7.6.6 of the Annexes to the Impact Assessment.
While the Board takes note that impacts are based on modelling, the results of the modelling should be critically reviewed to avoid false expectations, in view of many assumptions taken. For instance, the modelling results in the average level of wholesale prices at 74€/MWh already in 2020 and 103€/MWh in 2030). The attainment of these price levels is hard to imagine in reality, given that currently that level is around 34€ and more renewable capacity is being deployed into the system, still benefitting from the current support schemes for RES-E (based mostly on feed-in tariffs). Lower than modelled wholesale prices could seriously undermine the investment outcome, the assumed increased engagement of consumers and demand response – the cornerstones of the EU Energy Union.	To improve clarity, the new Box 9 includes further explanations. Please also see new footnotes 345 and 384 .
Similarly, the effectiveness of the revised RES-E support schemes (as proposed in the RED II IA) is not critically discussed. First, the report needs to emphasize that they would not be based on any type of feed-in tariff but premiums on top of market revenues and these premium will be auctioned. Second, the report needs to consider the fact that such auctions may not necessarily be effective in reducing the support to renewable energy sources. This is particularly relevant in a situation where the share of renewables in the electricity generation mix is expected to grow	It has been made clearer that market based support schemes, such as premium schemes combined with auctions, are an underlying premise of the impacts of the present initiative. (See section 1.1.1, 1.2.1, Box 7 under section 6.2.6.3, Box 9 underneath section 6.4.6 and Annex IV) The phase-out of non-market based support schemes has already commenced under the EEAG adopted in 2014 and is further reinforced by the measures proposed by RED II. It is therefore assumed that non-market based support schemes are fully

Comments made by RSB in second Opinion on 7 November 2016	Modifications made in reaction to comments RSB
substantially and the wholesale prices will be depressed at least until the current support schemes for RES-E are reviewed in 2024.	phased out by 2024, whereas the impact assessment looks at the situation in 2030. For more detail see Annex IV. The cost effectiveness of the RES E support schemes as such is the subject of the RED II impact assessment.
Procedure and presentation	
While the report is still very long, the inclusion of the abstract has improved the presentation of relevant information, though the issue of policy trade-offs (market vs. government interventions) should be emphasized more explicitly	References to policy trade-offs (market versus government intervention) have been further emphasised. See for instance the abstract, page 10 and 13 and Sections 6.2.2.1, 6.2.6.3 and 7.5.1. Furthermore, Options 2 and 3 under problem area II expressly seek to address the compatibility of government intervention in a market context.

An overview of evidence and external expertise used is provided in a separate annex.

Annex II: Stakeholder consultations

Public consultations

In preparation of the present initiative, the Commission has conducted several public consultations, in particular:

- public consultation on generation adequacy, capacity mechanisms, and the internal market in electricity, conducted in 2013;
- consultation on the retail energy market, conducted in 2014;
- public consultation on a new energy market design, conducted in 2015;
- public consultation on risk preparedness in the area of security of electricity supply, conducted in 2015.

These public consultation and their results are describe in more detail below.

Stakeholder opinions are also summarised in boxes for each main policy option in section 5 and, if appropariate, elsewhere of the present impact assessment. Even more detailed representations of stakeholder opinions are contained in Section 7 of each the annexes assessing the options for detailed measures.

Public consultation on generation adequacy, capacity mechanisms, and the internal market in electricity

Resource adequacy related issues were the subject of a public consultation[1] conducted from 15 November 2012 to 7 February 2013 through the *"Consultation on generation adequacy, capacity mechanisms, and the internal market in electricity"*. It was open to EU and Member States' authorities, energy market participants and their associations, and any other relevant stakeholders, including SMEs and energy consumers, and citizens. It aimed at obtaining stakeholder's views on ensuring resource adequacy and security of electricity supply in the internal market.

As regards the quality and representativeness of the consultation, the consultation received 148 individual responses from public bodies, industry (both energy producing and consuming) and academia. Most responses (72%) came from industry. Responses were of a high standard, not only engaging with the questions posed and the challenges being addressed, but bringing valuable insights to the Commission's reflections of this important topic. The consultation appears representative in comparison with similar consultations.

1 https://ec.europa.eu/energy/sites/ener/files/documents/20130207_generation_adequacy_consultation_document.pdf

The following paragraphs provide a summary of the responses available on the Commission's website[2]. The responses and a summary thereof are also available on the Commission's website[3].

(i) *Government interventions.* Respondents to the consultation responses repeatedly highlighted the policy uncertainty and national uncoordinated interventions of various kinds, in particular support for renewables, as being critical elements in discouraging investment. This was highlighted frequently by industry and also by academics and think tanks. The related issue of fixing the flaws of ETS was also raised repeatedly by industry. For example Energy UK states that *"national measures often response to a lack of coherence in EU energy policy itself – in particular there is a conflict between the market driven approach to liberalisation and to EU ETS and the various sectoral targets in renewables, energy efficiency etc."* The Netherlands (Ministry of Economic Affairs) *responded "the absence of a credible carbon policy and a lack of proper market functioning cannot be underestimated"*;

(ii) *Market functioning***.** In the context of a weak demand and economic crisis, Europe's energy markets today area was deemed characterised by two developments: the integration of large amounts of renewables and the implementation of the EU target model. This was clearly reflected in the responses to this consultation. Overall respondents' opinions were split as to whether energy-only markets could deliver investments needed to ensure generation adequacy and security of supply. However, there is near unanimous support from respondents for the importance of the completion of the integration of day-ahead, and close to real time markets as a an important contributor to security of supply although, some respondents caution that this will not address fundamental problems with whether energy-only markets can deliver resource adequacy Similarly, there are strong calls facilitating demand side response and the development of grids in line with the ten year network development plan. Almost all responses to the consultation raised the impact of RES E on the market. For example the UK response discusses the impact that more low marginal cost pricing will have on the market, and the issue is discussed in detail in the Clingendael paper submitted in response to the consultation. Industry in particular raised the issue about the impact that RES E support schemes had on the market. While many raise the issue of any out-of-market support creating distortions, the position set out in the response of Eneco, a Dutch company is worth quoting *"In general, support for specific energy sources does not undermine investments to ensure generation adequacy, it just changes the merit order. But details of support mechanisms can, specifically if a support mechanism lowers the value of flexibility"*. This consideration can be seen in the numbers of

2 https://ec.europa.eu/energy/sites/ener/files/documents/Charts_Public%20Consultation%20Retail%20Energy%20Market.pdf

3 https://ec.europa.eu/energy/en/consultations/consultation-generation-adequacy-capacity-mechanisms-and-internal-market-electricity

respondents who cite priority dispatch or lack of balancing responsibility for RES E producers as posing particular problems on the market, an issue which is separate from the level of support for RES producers, as indeed recognised by Germany who stat in their response *"Allerdigs ist ein Umstieg von der Festvergutuetung unter der garantierten Abnahme des EE-Stroms auf ein System der Marktintergration notwendig, in dem die Erneueuerbaren ihre Einspeisung an dem Marktpreissignal orientieren…"*.

(iii) *Assessing security of supply***.** There is widespread recognition of a need for improved assessment of generation and security of supply in the internal market given the impact of both RES E and market integration. Proposal have been made suggesting a need for more scenario analysis based on different weather conditions, different timespans for the assessment (long-term, short-term), more detailed assessment of flexibility and more coordination between TSOs and more sensitivity analysis. In this regard the existing ENTSO-E generation adequacy assessment is not felt to meet future needs, without suggesting that ENTSO-E is not carrying out its current role properly. There is particularly strong support for more regional generation adequacy assessments combined with a common methodology for undertaking such assessments. For example France in its response states *"Il pourrait notamment être utile de renforcer la cohérence à l'échelle régionale des différentes méthodes d'analyse et des scénarios produits au niveau national, souvent interdépendants. Ces analyses régionales viendraient ensuite alimenter un exercice réalisé à l'échelle de l'Union"*. Support for binding standards is less strong among respondents. Many of those who, in principle, would welcome common standards point to the difficulties in establishing such standards while MS retain responsibility for Security of Supply (and hence determining standards). Others (such as the Oeko institute) consider that more harmonised activities of Member states are essential in the internal market. There was limited support for a revision of the Security of Supply directive, which was perceived to fulfil its limited role. Again France states that *"Il apparaît préférable de privilégier l'élaboration rapide de ces codes et achever ainsi la mise en oeuvre des dispositions du 3ème paquet avant d'envisager des mesures nouvelles au travers de la refonte de cette directive."* However some stated that since the Directive was adopted before the Third Package, the situation after the Third Package is different and therefore the level of cooperation prescribed by the Directive does not correspond to today's situation. Summarising, there was widespread support for a reassessment of how generation adequacy and security of supply are assessed, and a recognition for the need for actions to be coordinated. The question which stands out is what are the best tools to do this. Here the electricity coordination group ('ECG') (explicitly mentioned by several respondents) can play a critical role. The Commission will continue to examine what are the best tools available to achieve the widely supported aim of improved generation adequacy assessment.

(iv) *Interventions to ensure security of supply*. As already noted opinion is divided on whether energy only markets can deliver the investments which will be needed to ensure generation adequacy and security of supply in the future. However, there were even more varied opinions on the effectiveness of different capacity remuneration mechanisms. Given this divergence of opinion therefore there is only limited support for a European blueprint, many respondents pointing to divergent local circumstances and the need to address specific problems as

militating against such an approach. Against this there was very strong support, particularly among industry and academica, for EU wide criteria, governing capacity mechanisms extending also to the high level criteria which proposed in the consultation paper. Among Member States the UK specifically called for criteria to be linked to State aid assessments, and notwithstanding caution about overly detailed assessment at EU level its detailed comments on the individual criteria in the consultation paper were broadly supportive. FR states *"Il est toutefois utile et légitime que la Commission européenne suive de près l'impact des choix des Etats membres sur le marché intérieur"* but also cautions that *"Il semble prématuré à ce stade de définir des critères détaillés de compatibilité avec le marché intérieur"*. DE states that the Commission *"im Bedarfsfall eintreten, der die Koordinierung zwischen den MS zu einer stärker gemeinsamen …Gewährleistung der Versorgungssicherheit erleichtert*.".

Consultation on the retail energy market

A public consultation dedicated to electricity retail markets and end-consumers[4] was conducted from 22 January 2014 to 17 April 2014. It was open to all EU citizens and organizations including public authorities, as well as relevant actors from outside the EU. This public consultation aimed at obtaining stakeholder's views on the functioning of retail energy markets.

As regards representativeness and quality, the Commission received 237 responses to the consultation. About 20% of submissions came from energy suppliers, 14% from DSOs, 7% from consumer organisations, and 4% from NRAs. A significant number of individual citizens also participated in the consultation.

The following paragraphs provide a summary of the responses, which are also available on the Commission's website[5].

(v) *Retail competition.* Respondents to this public consultation felt that market-based customer prices are an important factor in helping residential customers and SMEs better control their energy consumption and costs (129 out of 237 respondents considered that it was a very important factor while other 66 qualified it as important for the achievement of the said objective). Moreover, out of 121 respondents who considered that the level of competition in retail energy markets is too little, 45 recognised regulation of customer prices as one of the underlying drivers.

81% of the respondents agreed that allowing other parties to have access to consumption data in an appropriate and secure manner, subject to the consumer's explicit agreement, is a key enabler for the development of new energy services for consumers.

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4 https://ec.europa.eu/energy/en/consultations/consultation-retail-energy-market

5 https://ec.europa.eu/energy/sites/ener/files/documents/Charts_Public%20Consultation%20Retail%20Energy%20Market.pdf

As regards whether it is sufficiently easy without facing disproportionate permitting and grid connection procedures for a consumer to install and connect renewable energy generation and micro-CHP pursuant to the provisions of the RES and Energy performance in buildings Directives the views are split.

(vi) *Consumer issues.* 222 out of 237 respondents to the retail market public consultation believed that transparent contracts and bills were either important or very important for helping residential consumers and SMEs to better control their energy consumption and costs.

When asked to identify key factors influencing switching rates, 89 respondents out of 237 stated that consumers were not aware of their switching rights, 110 stated that prices and tariffs were too difficult to compare due to a lack of tools and/or due to contractual conditions, and 128 cited insufficient benefits from switching.

178 out of 237 agreed that ensuring the availability of web-based price comparison tools would increase consumers' interest in comparing offers and switching to a different energy supplier. 40 were neutral and 4 disagreed.

Only 32 out of 237 respondents agreed with the statement: "There is no need to encourage switching". 98 disagreed and 90 were neutral.

(vii) *DSOs and network tariffs.* The majority of the respondents consider that DSOs should carry out tasks such as data management, balancing of the local grid, including distributed generation and demand response, and connection of new generation/capacity (e.g. solar panels). The majority of stakeholders thought these activities should be carried out under good regulatory oversight, with sufficient independence from supply activities, while a clear definition of the role of DSOs (and TSOs), but also of the relationship with suppliers and consumers, is required.

Regarding distribution network tariffs, 34% of the respondents consider that European wide principles for setting distribution network tariffs are needed, while another 34% is neutral and 26% disagree. Time-differentiated tariffs are supported by ca 61% of the respondents, while the majority of stakeholders consider that cost breakdown (78%) and methodology (84%) of distribution network tariffs should be transparent.

The majority of stakeholders also consider that self-generators/auto-consumers should contribute to the network costs even if they use the network in a limited way. To this end, ca. 50% of the respondents consider that the further deployment of self-generation with auto-consumption requires a common approach as far as the contribution to network costs is concerned.

Regarding self- consumption, self- consumers should contribute to network costs even if they use the network in a limited way and further deployment would require a common approach. Moreover, however the responders think that to this end a common approach with simplified related administrative procedures is required. Granting of financial incentives by Member States to promote self-generation and auto-consumption splits views evenly.

(viii) *Demand response.* Over 50% of the responders think that residential consumers lack sufficient information to use energy efficiently and make use of advances in innovation that have enabled a broad range of distributed generation and demand response for industrial and commercial consumers. While the views are split in respect to the ESCOs role to facilitate the favourable contractual arrangements and other related services and as regards the access to respective choices of energy efficiency services consumers have. Similarly, responders' views diverge when assessing whether there should be done more to support the establishment of ESCOs that are active in the field of energy efficiency. In particular, 44% of the answers indicate that indeed there is more room to support ESCOs establishment and 28% of the answers received point out that are satisfied with the related service.

Moving on, the overwhelming majority industrial consumers are satisfied by their access to demand response and balancing services while on the same question the views coming from SMEs and commercial suppliers are split. Further, 24 of the residential consumers have access to demand response and balancing services while this percentage is 35% for the commercial sector and SMES and reached the 66% for industrial customers. As to the entity of the demand response service provider, over than 70% of the responders believe that this service should be provided by the suppliers, though 50% thinks that aggregators are also fit to provide the service while a minority would allocate this task to the DSOs.

Most responders view that they should be able to be participating in aggregation programmes irrespective of their load size in primary balance markets. The best way of making this happen is through aggregators and developing products taken into account consumers flexibility characteristics and size. In addition, responders' tend to agree that related demand response products should be hassle-free, applicable to all consumers' profiles. People also disagree with the claim that very specific data management tasks with regards to various distribution network actors should be defined at European level.

Suppliers are perceived as having the most access to dynamic pricing and/or time differentiated tariffs. They should first and aggregators, as a second choice, offer demand response services and dynamic pricing to residential consumers, SMEs. Unclear benefits, regulatory barriers and then unclear legal framework are identified as the greatest barriers to limited dynamic pricing in a country. Some respondents indicated that strengthening of infrastructure will allow greater retail market competition

Responses agree that consumers should have a right to a smart meter installed at their own request and at their expense also in regions without general rollout. However, there is a slight tendency against having the choice of a smart meter with functionalities of their own choice even if a different type is rolled out in their area. In respect to smart appliances and energy management systems, responders consider them as important to make the field of demand response accessible to a broad range of consumers and that they can work as facilitators to this end. The views also favour the display of consumption and consumption patterns by the smart appliances and do not consider this as a detriment to the consumers' comfort.

Public consultation on a new energy market design

A wide public consultation[6] on a new energy market design (COM(2015)340 was conducted from 15 July 2015 to 9 October 2015. It was open to EU and Member States' authorities, energy market participants and their associations, SMEs, energy consumers, NGOs, other relevant stakeholders and citizens. This public consultation aimed at obtaining stakeholder's views on the issues that may need to be addressed in a redesign of the European electricity market.

As regards representativeness and quality, the Commission received 320 replies to the consultation. About 50 % of submissions come from national or EU-wide industry associations. 26% of answers stem from undertakings active in the energy sector (suppliers, intermediaries, customers), 9% from network operators. 17 national governments and several national regulatory authorities submitted also a reply. A significant number of individual citizens and academic institutes participated in the consultation.

The first assessment of the submissions confirmed broad support of a number of key ideas of the planned market design initiative, while views on other issues vary. The following paragraphs provide a summary of the responses, also available on the Commission's website[7].

(i) *Electricity market adaptations*. A large majority of stakeholders agreed that scarcity pricing, i.e. price formation better reflecting actual demand and supply, is an important element in the future market design. It is perceived, along with current development of hedging products, as a way to enhance competitiveness. While single answers point at risks of more volatile pricing and price peaks (e.g. political acceptance, abuse of market power), others stress that those respective risks can be avoided (e.g. by hedging against volatility). Regulated prices are perceived as one of the most important obstacles to efficient scarcity pricing.

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

Many submissions highlight the link between scarcity pricing and incentives for investments/capacity remuneration mechanisms, as well as the crucial role of scarcity pricing for kick-starting demand response at industrial and household level.

6 https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design
7 https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

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

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

As concerns phasing out of public support schemes for RES, stakeholders take different positions. While some argue for phasing out support schemes as soon as possible, others argue that they will remain an important tool until technologies have fully matured. They point at existing fossil fuel subsidies and the need to continue subsidizing RES and maintaining other market corrections as long as subsidies for traditional fuels and nuclear are not removed. Certain stakeholders underline that support could progressively take more and more the form of investment aid (as opposed to operating aid). A large majority of stakeholders is in favour of some form of coordination of regional support schemes. The need for an ETS reform to allow full market integration of RES was mentioned very often. Most stakeholders agree that diversified charges and levies are a source of market distortions.

(ii) *Resource adequacy*. A majority of answering stakeholders is in favour an "energy-only" market, possibly augmented with a strategic reserve. Many generators and some governments disagree and are in favour of capacity remuneration mechanisms. Many stakeholders share the view that properly designed energy markets would make capacity mechanisms redundant.

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

(iii) *Retail issues*. Many stakeholders identified a lack of dynamic pricing (more flexible consumer prices, reflecting the actual supply and demand of electricity) as one of the main obstacles to kick-starting demand side response, along with the distortion of retail prices by taxes/levies and price regulation. Other factors include market rules that discriminate consumers or aggregators who want to offer demand response, network tariff structures that are not adapted to demand response and the slow roll-out of smart metering. Some stakeholders underline

that demand response should be purely market driven, where the potential is greater for industrial customers than for residential customers. Many replies point at specific regulatory barriers to demand response, primarily with regards to the lack of a standardised and harmonised framework for demand response (e.g. operation and settlement).

Regarding the role of DSOs, the respondents consider active system operation, neutral market facilitation and data hub management as possible functions for DSOs. Some stakeholders point at a potential conflict of interests for DSOs in their new role in case they are also active in the supply business and emphasized that the neutrality of DSOs should be ensured. A large number of the stakeholders stressed the importance of data protection and privacy, and consumer's ownership of data. Furthermore, a high number of respondents stressed the need of specific rules regarding access to data. As concerns a European approach on distribution tariffs, the views are mixed; the usefulness of some general principles is acknowledged by many stakeholders, while others stress that the concrete design should generally considered to be subject to national regulation.

(iv) *Regulatory framework/electricity market governance*. Stakeholders' opinions with regard to strengthening ACER's powers are divided. There is clear support for increasing ACER's legal powers by many stakeholders (e.g. oversight of ENTSO-E activities or decision powers for swifter alignment of NRA positions). However, the option to keep the *status quo* is also visibly present, notably in the submissions from Member States and national energy regulators. While some stakeholders mentioned a need for making ACER'S decisions more independent from national interests, others highlighted rather the need for appropriate financial and human resources for ACER to fulfil its tasks.

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

A majority of stakeholders support governance and regulatory oversight of power exchanges, particularly in relation to their role in market capacity. Other stakeholders are skeptical whether additional rules are needed given the existing rules in legislation on market coupling (CACM Guideline).

Stakeholders mention also that the role of DSOs and their governance should be clarified in an update to the 3rd Package.

(v) *Regionalisation of System Operation*. As concerns the proposal to foster regional cooperation of TSOs, a clear majority of stakeholders is in favour of closer *cooperation* between TSOs. Stakeholders mentioned different functions which could be better operated by TSOs in a regional set-up and called for less fragmentation in some important of the work of TSOs. Around half of those who want stronger TSO cooperation are also in favour of regional decision-making

responsibilities (e.g. for Regional Security Coordination Centres). Views were split on whether national security of supply responsibility is an obstacle to cross-border cooperation and whether regional responsibility would be an option.

Public consultation on risk preparedness in the area of security of electricity supply

A public consultation on risk preparedness in the area of security of electricity supply was organized between July 15th and October 9th 2015. This public consultation aimed at obtaining stakeholder's views in particular on how Member States should prepare themselves and co-operate with others, with a view to identify and manage risks relating to security of electricity supply.

The consulation resulted in 75 responses including public authorities (e.g. Ministries, NRAs), international organizations (e.g. IEA), European bodies (ACER, ENTSO-E) and most relevant stakeholders, including SMEs, industry and consumers associations, companies and citizens. The following paragraphs provide a summary of the responses.

The responses themselves as well as a summary thereof are also available on the Commission's website[8].

(i) *Obligation to draw up risk preparedness plans*. A large majority of respondents (75 %) is in favour of requiring Member States to draw up risk preparedness plans, covering results of risk assessments, preventive measures as well as measures to be taken in crisis situations.

There is also a large support for having common templates, which should ensure that a common approach is followed throughout Europe. Many respondents stress the need for common definitions, common assessment methods, and common rules on how to ensure security of supply.

In fact, most respondents acknowledge that in an increasingly interconnected electricity market, characterised by an increasing amount of variable supply, security of supply should be considered a matter of common concern (countries are increasingly dependent on one another and measures taken in one country can have a profound effect on what happens in neighbouring states and in electricity markets in general). They also acknowledge that the current legal framework (Directive 89/2005) does not offer the right framework for addressing this inter-dependence. Therefore, they take the view that risk preparedness plans based on common templates can help ensure that each Member State takes the measures needed to ensure security of supply whilst co-operating with and taking account of the needs of others. Stakeholders, in particular from the industry, also stress that risk preparedness plans should help ensure more transparency and reduce the scope for measures that unnecessarily distort markets.

Whilst acknowledging the need for a common approach, a significant number of stakeholders also state that there should be sufficient room for tailor-made,

[8] https://ec.europa.eu/energy/en/consultations/public-consultation-risk-preparedness-area-security-electricity-supply

national responses to security of supply concerns, as there are substantial differences between national electricity systems.

Respondents further agree that plans should be drawn up on a regular basis, proposals range from 2 to 5 years. The degree of transparency of the plans should depend on its content and may vary in function of it (given the fact that plans contain possibly sensitive information). Finally, respondents also warn against creating new administrative burdens and on this basis argue that any obligation to make risk preparedness plans should take account of already existing assessment and reporting obligations.

The minority of stakeholders taking the view that there should be no new legal obligation to draw up risk preparedness plans argue that such plans are already in place at the national level, that national electricity systems are profoundly different from one another and that priority should be given to the process of adopting network codes and guidelines.

(ii) *Content of risk preparedness plans / substantive requirements plans should comply with.* Many stakeholders take the view that it is too early at this stage to decide on the exact content of risk preparedness plans. They stress the need for more analysis, as well as in-depth discussions on the issue, in particular within the Electricity Coordination Group. In spite of this general caveat, consultation results already contain many useful pointers about substantive requirements plans should comply with:

- Definition of risks. Various stakeholders stress the need to develop a common definition of what security of supply means and the various risks that should be covered. Risk preparedness plans should be comprehensive in nature, covering generation adequacy and grid adequacy issues, as well as issues related to more short-term security issues (such the risk of a sudden unavailability of the grid or a power plant as a result of a terrorist attack);

- Cybersecurity. Respondents generally acknowledge the importance of preventing risks related to cyber-attacks but there is at this stage, no agreement on the need for further specific EU measures;

- Risk assessments and standards. Whilst the public consultation did not raise a specific question on risk assessment methods and standards (since these questions where covered by the market design consultation), various stakeholders make the case for a common methodology for assessing risks, to ensure a comparability of results, and a more common and transparent approach to the standards that are used to assess risks and define an acceptable level of reliability (this is also confirmed by replies to the market design consultation). Various stakeholders also take the view that risk preparedness plans should contain the results of various assessments made as well as the indicators used to make the assessments;

- Preventive measures. Stakeholders in favour of risk preparedness plans agree that such plans should identify both demand-side and supply-side measures taken to prevent security of supply issues, in particular situations of scarcity. They also agree on the need to assess the impact of existing and future interconnections and to take account of the import capacity when designing preventive measures. Many stakeholders point in this context to the need to ensure that markets function in an optimal way, thus allowing for flexibility in demand and a mix of solutions to ensure that a sufficient level of supply is guaranteed whilst keeping distortive measures at bay. Finally, stakeholders also stress that any assessment of import capacity should take account of the expected situation in neighbouring Member States;

- Dealing with emergency situations. A large majority of stakeholders agrees that plans should identify actions (market and non-market based) to be taken in emergency situations and rules on cooperation with other Member States. A majority also believes that plans should include provisions on the suspension of market activities, "protected customers" and cost compensation. Additionally, some stakeholders suggest lists of specific content for the emergency plans. As regards the development of new EU rules, many stakeholders state that due account should be taken of the network code on Emergency and Restoration, which is under preparation. Most say this draft network code should be considered as the basis, whilst acknowledging a possible need for additional common rules. A minority of stakeholders argues that the network code on emergency and restoration should be considered sufficient, leaving no need for additional EU-level rules, or consider that the issues not covered by the network code should not be addressed at the EU level;

- Definition/clarification of roles and responsibilities and what operational procedures to be followed (e.g., who to contact in times of crisis)

(iii) *Who should draw up risk preparedness plans, at what level, and with what kind of 'oversight'?*

- Who should be responsible for drawing up risk preparedness plans? Whilst most stakeholders recall that national governments have the ultimate responsibility for ensuring security of supply, many stakeholders consider that TSOs should take a lead role in drawing up risk preparedness plans. Most however consider that TSOs need to co-operate however with national ministries and/or national regulatory authorities, with the latter assuming a monitoring or supervisory role. There is a large support for a stronger DSO involvement in the preparation of the plans as well, as well as a clarification of the responsibilities of DSOs in crisis situations. Whilst most stakeholders see the added value of designating one 'competent authority' per Member States, there is no agreement on who that competent authority should be (and some argue that this choice should be left with the Member States).

- At what level should risk preparedness plans be drawn up? A large majority of respondents take the view that plans should be made at national level; however a large majority also stresses the need for more cross-border cooperation, at least in a regional context. A significant group of respondents argues that plans should be made at the regional level (for instance, as a complement to cross-border co-operation by TSOs in the frame of the regional security coordination initiatives) or call for plans at national and regional levels (or even 'multi-level' plans).[9] Those that argue in favour of national plans highlight the fact that responsibilities (and liabilities) for security of supply issues are national.[10] There is no agreement on how to 'define' regions for planning / co-operation purposes; most stakeholders suggest that synchronous areas and/or existing (voluntary) systems of regional co-operation should be used as a starting point. Finally, whilst only a minority calls for European plans, many see the need for some degree of co-ordination / alignment of plans in a European context (in particular via the development of common rules and peer reviews leading to best practice).

- What oversight should there be? Most stakeholders are in favour of a system of peer reviews, to be conducted either in a regional context, or in the frame of the Electricity Coordination Group. The latter should in any event be convened on a regular basis to serve as a forum for exchanging best practice. Some stakeholders are also in favour of a stronger role for ACER/ENTSO-E, in particular as regards more technical aspects of cross-border co-operation. As regards the Commission, stakeholders mainly see a facilitating role, but are often not in favour of a review system where the Commission takes binding decisions.

Aspects of the present initiative were also part of the consultation on the preparation of a **new Renewable Energy Directive** for the period after 2020[11] which was conducted from 18 November 2015 to 10 February 2016. It was open to EU and Member States' authorities, energy market participants and their associations, SMEs, energy consumers, NGOs, other relevant stakeholders and Citizens. The objective of this consultation was to consult stakeholders and citizens on the new renewable energy directive (RED II) for the period 2020-2030, foreseen before the end of 2016. The bioenergy sustainability policy, which will form part as well of the new renewable energy package, will be covered by a separate public consultation. The stakeholder responses to this consultation are descibed in more detail in the RED II impact assessment. A summary of the responses is however also available on the Commission's website[12].

Targeted consultations

A High Level Conference on electricity market design took place on 8 October 2015 in Florence.

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9 The rather cautious reaction to the idea of regional plans contrasts with the overwhelming support for regional assessments of generation adequacy under the market design consultation.

10 A similar concern is reflected in the market design consultation results.

11 https://ec.europa.eu/energy/en/consultations/preparation-new-renewable-energy-directive-period-after-2020

12 https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

The European Electricity Regulatory Forum convenes once or twice a year. The market design initiative was discussed in this stakeholder forum at several occasions, notably the Forum[13] that took place on 4-5 June 2015, 9 October 2015, 3-4 March 2016 and 13-14 June 2016.

The consumer- and retail- related aspects of the market design initiative were also discussed at the 8th Citizens' Energy Forum, which took place in London on 23 and 24 February 2016. The Commission established the London Forum to explore consumers' perspective and role in a competitive, 'smart', energy-efficient and fair energy retail market. It brings together representatives of consumer organisations, energy regulators, energy ombudsmen, energy industries, and national energy ministries.

The Electricity Coordination Group provide a platform for strategic exchanges between Member States, national regulators, ACER, ENTSOE and the Commission on electricity policy. This group was used to discuss issues related to the present impact assessment on 16 November 2015 and 3 May 2016.

On demand response two specifc stakeholder workshops were organised by the Commission: (i) Workshop on Status, Barriers and Incentives to Demand Response in EU Member States, organised be the European Commission on 23 October 2015, and (ii) Smart Grids Task Force, Expert Group 3 workshop on market design for demand response and self-consumption, March 2, 2016; and Expert Group 3 workshop on smart homes and buildings, April 26, 2016.

Member States' views

The support of Member States to the proposed initiatives is also apparent for instance from:

- The *"Council conclusions on implementation of the Energy Union"* of June 2015. In this regard, the conclusions state that: "*While STRESSING the importance of establishing a fully functioning and connected internal energy market that meets the needs of consumers, REAFFIRMS the need to fully implement and enforce existing EU legislation, including the Third Energy Package; the need to address the lack of energy interconnections, which may contribute to higher energy prices; the need for appropriate market price signals while improving competition in the retail markets; the need to address energy poverty, paying due attention to national specificities, and to assist consumers in vulnerable situations while seeking appropriate combination of social, energy or consumer policy; the need to inform and empower consumers with possibilities to participate actively in the energy market and respond to price signals in order to drive competition, to increase both supply-side and demand-side flexibility in the market, and to enable consumers to control their energy consumption and to participate in cost-*

13 http://www.ceer.eu/portal/page/portal/EER_HOME/EER_WORKSHOP/Stakeholder%20Fora/Florence_Fora

effective demand response solutions for example through smart grids and smart metres."[14]

- The *"Messages from the Presidency on electricity market design and regional cooperation"* of April 2016.[15] In these messages, the Presidency acknowledges the challenges facing the electricity markets in Europe and emphasizes, inter alia: the need to strengthen the functioning of the internal energy market; that correct price signals in all markets and for all actors are essential; that an integrated European electricity market requires well-functioning short-term markets and an adequate level of cross-border cooperation with regard to balancing markets; that security of supply would benefit from a more coordinated and efficient approach; that the future electricity retail markets should ensure access to new market players and facilitate introduction of innovative technologies, products and services.

Adherence to minimum Commission standards

The minimum Commission standards were all adhered to.

[14] http://data.consilium.europa.eu/doc/document/ST-9073-2015-INIT/en/pdf
[15] http://data.consilium.europa.eu/doc/document/ST-7879-2016-INIT/en/pdf

Annex III: Who is affected by the initiative and how

The present initiative covers a large area of measures. The tables below provide an overview of the parties affected, separately for each of the measures resulting from the preferred policy options developed in the Annexes 1.1 through to 7.6.

Such matters are equally referred to in section 6 of the main text for the (more aggregated) main policy options developed there.

Table 1. Persons affected by measure for Problem Area I, Option 1(a) (level playing field)

Affected party	Measure		
	1.1. Priority access and dispatch	**1.2. Regulatory exemptions from balancing responsibility**	**1.3. RES E access to provision of non-frequency ancillary services**
Member States	Need to change national legislation in so far as it contains priority dispatch; need to include provisions on transparency and compensation of curtailment and redispatch	Need to change national legislation in so far as it contains exemptions from balancing responsibility	They need to adapt national legislation to create conditions for non-discriminatory procurement of non-frequency ancillary services.
National regulatory authorities (NRAs)	Need to oversee implementation of provisions, notably determination which generators continue to benefit from priority rules, and ensure correct curtailment compensation.	Need to oversee implementation of provisions, notably oversight of TSOs.	They need to oversee implementation and monitoring of provisions, notably oversight of TSOs.
Transmission System Operators (TSOs)	Reduction of priority dispatch and priority access facilitates grid operation and lowers dispatch costs. Introduction of clear compensation rules on the other hand can increase redispatch costs where such compensation is currently insufficient.	Implementation of balancing rules, notably settlement of parties in imbalance.	They need to change the way non-frequency ancillary services are contracted, procured and possibly remunerated.
Distribution System Operators (DSOs)	Where DSOs curtail generation to resolve local grid constraints, they are affected identically to TSOs.	No direct impact, as balancing is the role of TSOs; indirectly, increased balancing responsibility of generators increases system transparency also to the benefit of DSOs.	DSOs very likely would also be affected, because most RES are connected at distribution level and the DSO's role in managing their network would have to change in order to allow RES assets to participate to the provision of ancillary services.
Generators	Generators currently subject to priority rules will be exposed to increased curtailment risks and lower likelihood of dispatch (for high marginal cost generators; likelihood of dispatch actually increases for low marginal cost generators) unless they continue to benefit from the exemptions. Generators not subject to exemptions will be less likely to be curtailed and more likely to be dispatched where they are the most efficient generator available. All generators will benefit from increased transparency and legal certainty on redispatch and curtailment compensation.	Balancing responsible parties, including suppliers, traders and generators currently subject to balancing responsibility are not directly impacted. Generators currently exempted or partly shielded from balancing responsibility will have to increase their efforts to remain in balance (e.g. through better use of weather forecasts) or will be exposed to financial risks.	Owners of generation assets (RES and not) would be affected by changes in the rules of how non-frequency ancillary services are procured. More transparent and competitive procurement rules could enable market entrance by new actors and technologies, such as battery storage.
Suppliers	Suppliers are not directly affected.	Balancing responsible parties, including suppliers, traders and generators currently subject to balancing responsibility are not directly impacted.	Most likely not affected.
Power exchanges	Power exchanges could benefit from the increased market liquidity particularly for short-term products which results from market-based curtailment and redispatch.	Power exchanges could benefit from the increased market liquidity particularly for short-term products which results from balancing responsibility of RES E.	Most likely not affected.
Aggregators	Aggregators are likely to benefit in particular by offering market-based resources to be used by TSOs in redispatch or curtailment.	Aggregators are likely to benefit in particular by offering to small generators services to fulfil their balancing responsibility.	Aggregators are likely to benefit from a more level playing field and get access to additional remuneration streams.
End consumers	End consumers are not directly affected.	End consumers are not directly affected.	End consumers are not directly affected.

Table 2. Persons affected by measure for problem Area I, Option 1(b) (Strengthening short-term markets)

Affected party	Measure		
	2.1. Reserves sizing and procurement	**2.2. Removing distortions for liquid short-term markets**	**2.3. Improving the coordination of Transmission System Operation**
Member States	Member State authorities define the country's overall policy regarding energy mix and power grid investments.	Member States authorities generally play a limited direct role in the operation of intraday markets. They will, however be impacted if they are responsible for implementing/enforcing requirements.	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements. This topic is likely to have a particularly political angle, as Member States may not be willing to entrust ROCs with decision-making powers under the assumption that security of supply is a national responsibility (although based on the TFEU, it constitutes a shared responsibility between the EU and MS).
National regulatory authorities (NRAs)	NRAs approve the methodology for sizing and procurement of balancing reserves. They are also responsible for any impact on TSOs' tariffs and how cross-border infrastructure is allocated.	NRAs are responsible for regulatory oversight of intraday markets, including as part of the implementation of the CACM Guideline, where they are responsible for approving a number of methodology developed by TSOs and power exchanges. They will, therefore, be affected by changes in so far as it could alter the basis for their regulatory decisions. However, the direct impact on NRAs is anticipated to be relatively limited.	NRAs of each of the regions where a ROC is established would be required to carry out the regional oversight of the concerned ROC. This would include competences at least equivalent to those established for NRAs in the Third Energy Package. It may be necessary to entrust ACER with the EU-wide oversight of ROCs. It would be necessary to set out a framework for the interaction between the regional groupings of NRAs and ACER.
Transmission System Operators (TSOs)	TSOs analyse system's state and propose the methodology for sizing and procurement of balancing reserves in their control areas. Shifting responsibilities for sizing and procurement of balancing reserves at regional level implies a need for strong governance at regional level. Existing physical constraints would still need to be taken into account in the regional procurement platform. Major impacts are expected on the current design of system operation procedures and responsibilities. Cost allocation and remuneration would have to be agreed, requiring the development of a clear and robust framework of responsibilities between national and regional TSOs.	TSOs are heavily involved in the operation of intraday markets, notably in determining the cross-border capacity made available to the market, and in using the results for operation of the system. They are therefore likely to be significantly impacted by any changes.	National TSOs would be complemented by ROCs performing functions of regional relevance, whilst real time operation functions would be left solely in the hands of national TSOs. ROCs could potentially be entrusted with certain decision making responsibilities for a limited number of operational functions, whilst TSOs would retain their responsibility as regards all other functions for which they are currently responsible at national level. It may be necessary to entrust additional tasks to ENTSO-E related to the cooperation and coordination between ROCs.
Generators	Generators, as Balancing Service Providers, would have additional opportunity to participate in the balancing market even though significant operational impact might increase due to the procurement frequency. Such framework would, however, allow the participation of renewable energy sources in the balancing market potentially leading to a sharp decrease of balancing reserve cost.	Generators will be affected by any changes in wholesale prices they receive for their energy on the intraday market. More efficient price signals, and more potential for trading, will open up the market to smaller generators, particularly renewable.	Generators could benefit from a more secure power system and a more efficient market leading to increased market opportunities.
Aggregators	Smaller products and time units will give aggregators more access to intraday markets.	Increased price fluctuations will give aggregators more opportunities to operate, thereby helping to ensure that demand meets supply at any point in time.	Limited impact on aggregators.
Suppliers	Regional procurement of reserves would lead to regional settlement of imbalances; therefore allowing for increase competition of suppliers across borders.	Suppliers will be affected insofar as they are the ones who buy power on the wholesale market. Any changes in intraday clearing prices will change how much they pay for their power, the extent to which will depend on how much trading they do in the intraday market.	Limited impact on suppliers.
Power exchanges	In case an optimisation process for the allocation of transmission capacity between energy and balancing markets has to developed, day-ahead market coupling algorithm currently operates by power exchanges might be	Power exchanges will be the most affected by any changes to intraday arrangements, as they are the ones who operate the platforms on which energy is traded in the intraday timeframe. They will therefore have to adapt systems and process to meet new requirements.	Limited impact on power exchanges. It is expected that they could benefit power exchanges as the optimisation of market-related functions such as capacity calculation would entail more liquidity in the markets that could be exchanged.

Affected party	Measure		
	2.1. Reserves sizing and procurement	**2.2. Removing distortions for liquid short-term markets**	**2.3. Improving the coordination of Transmission System Operation**
	impacted and solution will have to be found on sharing transmission capacity in an optimal way for the markets preceding the balancing market.		
End consumers	End consumers will be able to participate in balancing markets via demand response aggregators allowing for stronger supplier's competition at regional level.	End consumers will be affected insofar as changes to the wholesale price are passed on to them in their retail price.	Regional TSO cooperation through the creation of ROCs would benefit consumers through improved security of supply (by minimising the risk of wide area events such as brownouts and blackouts), and lowering costs through increased efficiency in system operation and maximised availability of transmission capacity to market participants.

Table 3. Persons affected by measure for Problem Area I, Option 1(c) (Pulling demand response and distributed resourced into the market)

Affected party	Measure			
	3.1. Unlocking demand side response	**3.2. Distribution networks**	**3.3. Distribution network tariffs and DSO remuneration**	**3.4. Improving the institutional framework**
Member States	Those 17 Member States that roll out smart meters will not be affected by the new provisions on smart meters, apart from the obligation to comply with the recommended functionalities, which may need to transpose into national legislation. Similarly for those two Member States that opted for partial roll-out and are not expected to face any other additional burden from allowing additional consumers to request smart meters. However, those 9 Member States that currently do not plan to install any smart meters will need to establish legislation with technical and functional requirements for the roll-out and face some additional administrative impact by re-evaluating their cost-benefit analyses. What concerns market rules for demand response, Member States are already obliged through the EED to enable demand response. The new provisions will rather provide additional guidance for Member States on how to create the enabling framework instead of imposing additional burden to them.	The competent ministries in each Member State who will be involved in the transposition of the relevant EU legislation and monitor the implementation and effectiveness of the measures under the preferred option.	The competent ministries in each Member State who will be involved in the transposition of the relevant EU legislation and monitor the implementation and effectiveness of the measures under the preferred option.	MS authorities will be in charge of national implementation of the revised Third Package.
National regulatory authorities (NRAs)	Additional administrative impact may be created for the NRAs for enforcing actions regarding the consumer entitlement to request a fully functional smart meter. This includes assessing the costs to be borne by the consumer, and overseeing the process of deployment. At the same time, improved consumer engagement thanks to smart metering, would make it easier for NRAs to ensure proper functioning of the national (retail) energy markets. Already under the existing legislation NRAs are obliged to encourage demand side resources to participate alongside supply in markets. The new provisions under the preferred option only further specify which aspects have to be addressed by NRAs but they do not create additional burden for them.	As DSOs are regulated entities is expected that NRAs will have the main role of ensuring the effective application of measures. NRAs will be mostly involved in the application of the measures and in designing the necessary rules for the practical implementation. As the measures under the preferred option are closely linked to a suitable remuneration methodology, NRAs will also probably have to modify existing schemes. This will require the availability of the necessary human, technical and financial resources.	According to the Electricity Directive NRAs have the main role in fixing or approving network tariffs or their methodologies. The overall aim is to move towards more sophisticated network tariff methodologies. To this end, some NRAs might have to modify the existing methodologies for distribution tariffs. The introduction of smarter regulatory frameworks will require the availability of the necessary human, technical and financial resources.	Their role, powers and responsibilities will be further clarified, especially as regards issues which are relevant at regional/EU level. This will affect the way NRAs have cooperated at regional and EU-level, including within ACER, in order to enhance the collaboration between NRAs and ACER. In the context of clarifying the respective roles of NRAs and ACER, some of the powers and responsibilities currently conferred to NRAs may be shifted to ACER.
Agency for the cooperation of energy regulators (ACER)	Apart from the minor changes necessary to ensure effective market monitoring in the changed market context, ACER will not be affected by changes in unlocking demand side response..	ACER will be affected to the extent which will be called to oversight the activities of EU DSO entity and its involvement in relevant network codes or guidelines.	ACER will be affected to the extent which will be called to oversight the activities of EU DSO entity and its involvement in network codes or guidelines on network tariffs.	Its role, powers and responsibilities will be further enhanced in order to ensure that ACER can continue fulfilling its role of supporting NRAs in exercising their functions at EU level and to coordinate their actions where necessary. For a number of specific and defined instances, some of the powers and responsibilities of NRAs will be shifted to

Affected party	Measure			
	3.1. Unlocking demand side response	**3.2. Distribution networks**	**3.3. Distribution network tariffs and DSO remuneration**	**3.4. Improving the institutional framework**
				ACER, to ensure that it can carry out an EU-level oversight. ACER's role will be affected by the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines.
Transmission System Operators (TSOs)	A greater roll-out of smart meters allows TSOs to better calculate settlements and balancing penalties as the consumption figures can be based on real consumption data and not only on profiles. TSOs are affected by opening markets for aggregated loads and demand response. Those effects are dealt with in the Impact Assessment on markets. TSOs are not directly affected by the proposed measures on removing market barriers for independent aggregators. However, they are indirectly affected: A greater participation of flexibility products in ancillary service markets (e.g. balancing markets) can help TSOs cost-effectively manage the network.	TSOs will be involved as more coordination with DSOs will be required. TSOs will have to allocate the necessary human and technical resources in order to achieve such coordination.	TSOs will not be affected by changes in distribution tariffs.	Some of the transparency obligations imposed on ENTSO-E as well as some of the governance rules applying to this association will indirectly affect TSOs. Some of the proposed rules (e.g. co-financing of ACER by contributions from market participants) might directly impact on TSOs.
European network of transmission system operators (ENTSOs)	ENTSO-E will not be affected by changes in unlocking demand response.	ENTSO-E will have to cooperate with the EU DSO entity on issues which are relevant to both transmission and distribution networks.	ENTSO-E will not be affected by changes in distribution tariffs.	ENTSO-E's mandate will be mainly clarified, whilst ensuring that its added value of providing technical expertise is preserved. Transparency of ENTSO-E will be further improved. The role of ENTSO-E will be affected by the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines.
Distribution System Operators (DSOs)	In most Member States, DSOs are responsible for organising the installation of smart meters. The additional costs to be determined by the NRAs can however be charged to the users. DSOs also benefit from access to real time data coming from smart metering. It supports them in their work on monitoring and controlling the network, improving its reliability and power quality, and its overall effectiveness, particularly in the presence of distributed generation. This ultimately contributes to the increased distribution network efficiency and increased revenue for the DSOs (e.g. via reduced technical and commercial losses) DSOs are not directly affected by the proposed measures on removing market barriers for independent aggregators. However, DSOs can	DSOs will be directly affected by the possible measures under the preferred option as they will have to have in place the necessary human and technical resources in order to implement the envisaged measures. Additional personnel or infrastructure might be necessary. However, DSOs will use flexibility solutions in order to increase efficiencies, only where benefits will outweigh additional costs.	It is expected that the envisaged measures under the preferred option will positively affect DSOs as they aim to a more efficient utilisation of the distribution system and the incentivisation of DSOs towards more optimal development and operation of their grids. More advanced tariff schemes may require the availability and monitoring of detailed data (financial and technical) and the achievement of specific targets. Any additional administrative costs should be offset by the expected benefits.	DSOs will be able to participate more actively as a result of the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines.

Affected party	Measure			
	3.1. Unlocking demand side response	**3.2. Distribution networks**	**3.3. Distribution network tariffs and DSO remuneration**	**3.4. Improving the institutional framework**
	indirectly benefit from a better uptake of demand response as the reduction in peaks it will reduce the need to invest in distribution networks.			
Generators	Demand response is designed to reduce peak demand and thereby effectively replace marginal power plants and reduce electricity prices at the wholesale market. As such generators are likely to face reduced turnover from lower peak prices and from operating reserve capacities. Generators are not likely to be effected by an accelerated smart meter roll out.	Generators will not be affected by the measures under the preferred option.	The envisaged measures aim to the overall reduction of network costs through the incentivisation of DSOs to raise efficiencies, which will have an overall positive impact to system users. The envisaged measures also aim to a fair allocation of costs among different system users. Therefore, to the extent to which the envisaged measures will incite changes in existing tariffs, generators or other system users may be affected from any new tariffs which will result to reallocation of costs.	Generators will be able to participate more actively as a result of the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines.
Suppliers	Smart meters can have a direct impact on suppliers, as they enable consumers to easily switch. Furthermore, there is one Member State where suppliers are responsible for the roll-out. Moreover, smart metering allows suppliers to offer dynamic pricing contracts that reduce suppliers' risk of changing wholesale prices. The effect of demand response on suppliers can be positive as suppliers will benefit from lower wholesale prices. On the other hand demand response will make it more difficult for suppliers to calculate retail prices. Also as balancing responsible parties they may face higher penalty payments for imbalances incurred due to their customers changing consumption patterns. Finally, new competition from aggregators may reduce their income. However, suppliers can also offer demand response services to their customers and expand their range of services and thereby turnover. The overall financial impact of smart meters and of more competition through demand response on suppliers will hence depend on the ability of the individual supplier to adapt to the new market with innovative services and competitive pricing offers.	Suppliers will not be affected as the envisaged measures will not affect their normal business.	It is not expected that the envisaged measures will affect the suppliers.	Suppliers will be able to participate more actively as a result of the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines.
Power exchanges	No impact expected	No impact expected	No impact expected	Power exchanges will be subject to an enhanced regulatory oversight at EU level exercised by ACER and NRAs. Power exchanges will be able to participate more actively as a result of the changes envisaged for the process of development of Commission implementing regulations in the

Affected party	Measure			
	3.1. Unlocking demand side response	**3.2. Distribution networks**	**3.3. Distribution network tariffs and DSO remuneration**	**3.4. Improving the institutional framework**
				form of network codes and guidelines.
Aggregators (and other new market entrants)	Aggregators are likely to benefit from an accelerated roll out of smart meters as this technology facilitates market access for demand service providers and aggregators. Equally all measures aimed at removing market barriers and increasing competition in the retail market will immediately facilitate market access for aggregators and new energy service providers and hence opens new business opportunities for them.	Aggregators will be positively affected as DSOs will request their services in order to use flexibility for managing congestion in their networks.	Insofar as distribution tariffs incentivise grid users to use the network more efficiently, aggregators will not be called upon as much to help to manage network congestion..	Aggregators and other new market entrants will be able to participate more actively as a result of the changes envisaged for the process of development of Commission implementing regulations in the form of network codes and guidelines
End consumers	End consumers will get the right to request smart meters and have access to dynamic electricity pricing contracts which clearly gives puts them in a position to become active market participants. Furthermore, provision of accurate and reliable data flows due to smart metering would enable easier and quicker switch between suppliers, access to choices, smart home solutions and innovative automation services, and can also lead to energy savings. Consumers will equally benefit from more competition, wider choice, and the possibility to actively engage in price based and incentive based demand response and hence from reduced energy bills. But also those consumers who do not engage themselves in demand response can profit from lower wholesale prices as a result of demand response if those price reductions are being passed on to consumers.	Use of flexibility from DSOs will result to lower network costs. This reduction will be reflected in distribution tariffs and the final electricity bill of the consumer.	The envisaged measures aim to the overall reduction of network costs through the incentivisation of DSOs to raise efficiencies, which will have an overall positive impact to system users. The measures also aim to a fair allocation of costs among different system users. Therefore, to the extent to which the envisaged measures will incite changes in existing tariffs, consumers or other system users may be affected from any new tariffs which will result to reallocation of costs.	Consumers will be able to benefit from enhanced transparency and in general from well-functioning energy markets.

Table 4. Persons affected by measure Problem Area II, Option 1 (Improved energy market without CMs)

Affected party	Measure			
	4.1. Removing price caps	**4.2. Improving locational price signals**	**4.3. Minimise investment and dispatch distortions due to transmission tariff structures**	**4.4. Congestion income spending to increase cross-border capacity**
Member States	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements.	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements. This topic is likely to have a particularly political angle, as splitting price zones within a Member State will result in different wholesale electricity in that Member State depending on location (although not necessarily retail prices).	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements.	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements.
National regulatory authorities (NRAs)	NRAs will be impacted if they are responsible for implementing/enforcing/monitoring the requirements.	Member States authorities will be impacted if they are responsible for implementing/enforcing/monitoring the requirements.	NRAs play a significant role in monitoring, authorising, etc. tariffs and connection charges. Any change would impact on how they do this.	NRAs are currently responsible for reviewing the use of congestion income, and for authorising it to be spent on the reduction of tariffs. They will be affected by Option 2 and 3 as they no longer need to authorise it to be spent on the reduction of tariffs. Option 1 could require them to make a more them to make a more thorough assessment. ACER will be affected by changes to monitoring and transparency requirements and the requirement on them to develop harmonised rules.
Transmission System Operators (TSOs)	There will be limited impact on TSOs.	TSOs will be affected as it will likely mean they hold and operate networks over more than one price zone. It will also change those transmission lines that accumulate revenue from congestion.	Changes would have limited impact on TSOs themselves, as proposals are not generally looking at how TSOs are remunerated, but rather how the money is collected.	It will change how transmission system operators are able to use congestion income. Options 1-3 could lead to more investment activity of the TSO.
Generators	Increased price variability will impact the revenue generators will see from the energy market – they will likely see higher prices for short periods of time, which will incentivise flexible generation.	Different price zones will change the prices that generators receive depending on their location.	Changes would most affect generators – lower connection charges or tariffs (where they are applied to generators) would have a positive impact on their revenues.	If Option 1, 2 and 3 lead to more investment in networks, this would impact generators by delivering more cross-border competition and present further trading opportunities to sell energy by an increases in the liquidity of cross-border markets.

Affected party	Measure			
	4.1. Removing price caps	**4.2. Improving locational price signals**	**4.3. Minimise investment and dispatch distortions due to transmission tariff structures**	**4.4. Congestion income spending to increase cross-border capacity**
Suppliers	Increased price variability will impact the price paid by suppliers - – they will likely see higher prices for short periods of time.	Different price zones will change the prices that suppliers pay depending on their location.	Limited impact on suppliers.	If Option 1, 2 and 3 lead to more investment in networks, this would impact generators by delivering more cross-border competition and present further trading opportunities to buy energy by an increase in the liquidity of cross-border markets.
Power exchanges	Power exchanges will be required to implement the requirements, which could require changes to systems and practices.	Different price zone will change the practices of power exchanges – currently they operate based on MS-level markets (in general) – they would need to differential markets based on different price boundaries.	Limited impact on power exchanges.	If Option 1, 2 and 3 lead to more investment in networks, this would impact power exchanges if it leads to greater cross-border trade on their platforms.
End consumers	End consumers will be affected insofar as changes to the wholesale price are passed on to them in their retail price. However, more variable prices will not necessarily be felt by end-consumers as they may be hedged (particularly household) against this volatility in their retail contracts.	Different price zones *could* affect end-consumers depending on their location. However, possibilities exist to retail MS-level retail prices,	End consumers could be affected if more tariffs were charged on load, as opposed to production. However, overall the impact is likely to be similar as the overall cost basis would not changing.	End consumers may be affected by any reduction in the amount that can be offset against tariffs. However, this may be outweighed by the positive effect of more cross-border capacity being available, and the benefit this has on competition and energy prices.

Table 5. Persons affected by measures of Problem Area II, Option 2 (Improved energy market, CMs based on an EU-wide adequacy assessment) and Option 3 (Improved energy market, CMs based on an EU-wide adequacy assessment, plus cross-border participation

Affected party	Measure	
	5.1. Improved generation adequacy methodology	**5.2. Cross-border operation of capacity mechanisms**
Member States	Member States would be better informed about the likely development of security of supply indicators and would have to exclusively rely on the EU-wide generation adequacy assessment carried out by ENTSO-E when arguing for CMs.	Each Member State would not need to design a separate individual solution – and this would potentially reduce the need for bilateral negotiations between TSOs.
National regulatory authorities (NRAs)	NRAs/ ACER would be required to approve the methodology used by ENTSO-E for the generation adequacy methodology and potentially endorse the assessment.	NRAs/ ACER would be required to set the obligations and penalties for non-availability for both participating generation/ demand resources and cross-border transmission infrastructure.
Transmission System Operators (TSOs)	TSOs would be obliged to provide national raw data to ENTSO-E which will be used in the EU-wide generation adequacy assessment.	ENTSO-E would be required to establish an appropriate methodology for calculating suitable capacity values up to which cross-border participation would be possible. Based on the ENTSO-E methodology, TSOs would be required to calculate the capacity values for each of their borders. They might potentially be penalized for non-availability of transmission infrastructure. TSOs would be required to check effective availability of participating resources. ENTSO-E may also be required to establish common rules for crediting foreign capacity resources for the purpose of participation in CMs reflecting the likely availability of resources in each country/zone.
Generators	ENTSO-E would also have to provide for an updated methodology with probabilistic calculations, appropriate coverage of interdependencies, availability of RES and demand side flexibility and availability of cross-border infrastructure.	Foreign capacity providers would participate directly into a national capacity auction, with availability rather than delivery obligations imposed on the foreign capacity providers and the cross-border infrastructure. Foreign capacity providers/ interconnectors would be remunerated for the security of supply benefits that they deliver to the CM zone and would receive penalties for non-availability.
Suppliers	ENTSO-E would be required to carry out an EU-wide or regional system adequacy assessment based on national raw data provided by TSOs (as opposed to a compilation of national assessments).	Limited impact on suppliers
Aggregators	With the updated methodology provided by ENTSO-E, intermittent RES generators/ demand-side flexibility would be less likely to be excluded from contributing to generation adequacy.	Just like generators they shall be able to participate in cross-border CMs.
Power exchanges	Limited impact on suppliers	Limited impact on power exchanges
End consumers	Limited impact on aggregators	Explicit cross-border participation in CMs would preserve the properties of market coupling and ensure that the distortions of uncoordinated national mechanisms are corrected and the internal market is able to deliver the benefits to consumers.

Table 6. Persons affected by measures for Problem Area III

Affected party	Measure
Member States	Member States (i.e. responsible ministries) would bear the main responsibility of preparing Risk Preparedness Plans and coordinating relevant parts with other Member States from their region, including ex-ante agreements on assistance during (simultaneous) crisis and financial compensation. Member States would designate a ministry or the NRA as 'competent authority' as responsible body for preparing the Risk Preparedness Plan and for cross-border coordination in crisis. As members of an empowered Electricity Coordination Group they would consult and coordinate Plans. The above described responsibilities might involve an increased administrative impact. However, most of the tasks are already carried out in a purely national context and there might also be benefits from exploiting synergies of improved cooperation. In addition, existing national reporting obligations would be reduced (e.g. repealing the obligation of Article 4 of Electricity Directive "Monitoring security of supply").
National regulatory authorities (NRAs)	NRAs could possibly fulfil certain tasks as part of the Risk Preparedness Plan of their Member State. Furthermore they might be appointed as 'competent authority' by Member States. In this case, they would be responsible for preparing the Risk Preparedness Plan and for cross-border coordination during crisis, possibly requiring additional resources.
Transmission System Operators (TSOs)	ENTSO-E would be responsible for identification of crisis scenarios and risk assessment in a regional context. A common methodology for short-term assessments (ENTSO-E Seasonal Outlooks and the week-ahead assessments of the RSCs) should be developed by ENTSO-E. This might require additional resources within ENTSO-E and within the RSCs, in case that ENTSO-E delegates all or part of these tasks to them. However, additional costs would be limited as some of these tasks are already carried out today. Giving these bodies a clear mandate, it would however significantly improve cross-border coordination.
Generators	Generation companies and other market participants would not be directly affected by preparation of Risk Preparedness Plans. However, they would benefit from clearer rules on crisis management and the prevention of unjustified market intervention.
Suppliers	Market participants would not be directly affected by preparation of Risk Preparedness Plans. However, they would benefit from clearer rules on crisis management and the prevention of unjustified market intervention.
Aggregators	Market participants would not be directly affected by preparation of Risk Preparedness Plans. However, they would benefit from clearer rules on crisis management and the prevention of unjustified market intervention.
Power exchanges	Market operators would not be directly affected by preparation of Risk Preparedness Plans. However, they would benefit from clearer rules on crisis management and the prevention of unjustified market intervention.
End consumers	As described above the impacts of blackouts on industry and society proved to be severe. Consequently, end consumers benefit extensively from improved risk preparedness as it would help to prevent future blackouts more effectively.

Table 7.a Persons affected by measure for Problem Area IV

Affected party	Measure		
	7.1. Monitoring energy poverty	**7.2. Options for phasing out regulated prices**	**7.3. Creating a level playing field for access to data**
Member States	Option 1 leads to an improved framework to measure energy poverty. Member States will have a better understanding of energy poverty as a result of a clearer conceptual framework (through the common understanding of energy poverty) and better information on the level of energy poverty (measuring energy poverty). Ultimately, this will contribute to better identification and targeted public policies to alleviate energy poverty.	Those Member States still practicing some form of price regulation will have to make the necessary legislative and market changes in order to ensure a smooth and effective phase out.	The competent ministries and authorities who will be involved in the transposition of the relevant EU legislation and will monitor the implementation and effectiveness of the measures under the preferred option.
National regulatory authorities (NRAs)	NRAs will need to monitor and report to the European Commission and ACER the number of disconnections. According to ACER Market Monitoring Report, only 16 Member States met this requirement.	In most countries with price regulation, NRAs are the bodies responsible for setting the level of regulated prices for a defined regulatory period. In few cases NRAs are only giving their opinion on regulated prices set by the government. Phasing-out regulated prices would remove these responsibilities of the NRAs therefore reducing administrative costs and resource needs. However new tasks for the NRAs might be defined by Member States in the follow-up of the price deregulation process such as monitoring the level of market prices with the possibility to intervene ex post in the price setting in case of market abuse. The costs of carrying out such new tasks are likely to be less important than the costs of setting regulated prices, resulting overall in reduces resource needs for the NRAs.	The envisaged measures will partly affect the NRAs as most probably will have a role in the implementation of the measures at national level. Other authorities such as data protection authorities may be involved in the implementation of the envisaged measures at national level. NRAs will have to monitor the data handling procedures as part of the retail market functioning. The involvement of NRAs is expected to be higher in Member States where smart metering systems are deployed.
Transmission System Operators (TSOs)	The preferred option would not directly affect TSOs.	The preferred option would not directly affect TSOs.	TSOs might be affected in terms of costs in cases where Member States will decide that they are responsible for the operation of the data-hub. However, the envisaged measures do not impose an obligation to Member States regarding the data management model and the party responsible for acting as a data-hub. The measures under the preferred option will benefit TSOs and other operators as the will allow them, under specific terms, to have access to aggregated information which will be useful for network planning and operation.
Distribution System Operators (DSOs)	The preferred option would not directly affect DSOs.	The preferred option would not directly affect DSOs.	In the large majority of Member States DSOs will be involved directly in the data handling process. DSOs will have the same benefits as TSOs in terms of system operation and planning. Under the preferred option DSOs which are not fully unbundled (DSOs below the 100.000 threshold) will have to implement measures which link to the non-discriminatory treatment of information. The implementation of such measures will most probably create costs which will vary depending on the national framework. It is not expected however that these costs will create a high burden, as they can implemented through automated IT systems.

Affected party	Measure		
	7.1. Monitoring energy poverty	**7.2. Options for phasing out regulated prices**	**7.3. Creating a level playing field for access to data**
Generators	The preferred option would not directly affect generators.	In countries where artificially low regulated end-user prices are backed up by generation deliveries at non cost-reflective level agreed by long-term contracts, deregulation of end user prices could trigger a rethinking of such system by a renegotiation of long-term contracts which would stimulate investment in efficient generation capacities with positive effects on the competition on the generation market.	Generators will not be affected under the preferred option.
Suppliers	The preferred option would not directly affect suppliers. However, should the improved monitoring of energy poverty lead to increased action to tackle the problem by Member States, then the costs of these measures may be borne by suppliers. Depending on each Member States, these costs may then be recovered as network charges, passed on to consumers or taken against energy providers overall benefits. Preventative measures, such as debt management or providing additional information on where to find support, represent an additional cost to energy retailers in those Member States where these measures are not yet in place. A moratorium of disconnection will reduce energy retailers' revenue as energy will be supplied free of charge. However, such costs will to some extent be mitigated by lower numbers of bad debtors in the long run.	Alternative (non-regulated) suppliers would benefit from the deregulation of prices by increased possibilities to compete on the price and therefore to gain more market share. This is particularly true for countries where regulated prices set at non cost-reflective levels prevent alternative suppliers from contesting the regulated offer. For the regulated suppliers (usually former incumbents) the removal of price regulation would lead to increased operational costs related to the implementation of the transition from the regulated offer to market based offer for its customer base. Moreover, regulated suppliers are likely to lose significant market shares if customers will switch to competitive offers of alternative suppliers.	The availability of consumption data under non-discriminatory terms and interoperability of data formats will have positive effects on suppliers and other retailers. The aim of the measures under the preferred option is to bring down the administrative costs for the various retail service providers including suppliers.
Power exchanges	The preferred option would not directly affect power exchanges.	The preferred option would not directly affect power exchanges. However, power exchanges could benefit from increased liquidity due to better functioning competition on retail and wholesale markets following price deregulation.	-
Aggregators	The preferred option would not directly affect aggregators.	Removing price regulation would stimulate the development of energy services which create market opportunities for aggregators.	In the preferred option aggregators and other retail service providers will have equal access to data as suppliers in a transparent and non-discriminatory way. This will allow aggregators to develop new services for consumers and will facilitate their entrance in the market.
Consumers	Consumers in a situation of energy poverty or at risk of energy poverty will be positively impacted by the preferred option. A clearer understanding and measuring of energy poverty will have positive impacts on Member States efforts to tackle energy poverty..	Phase-out of regulated prices for end customers would stimulate competition on retail markets which translates for customers into more choice and better offers in terms of price and service quality. Customers would be able to better manage their own energy consumption by using energy services and technologies such as demand response, self-generation, and self-consumption. However, notably in countries where prices are artificially regulated at low levels, price deregulation could be followed by substantial increases in end user prices; to help customers face such price increases, appropriate protection measures for vulnerable customers should be in place prior to deregulation.	The envisaged measures under the preferred option aim to support the development of a competitive retail market. It is expected that the measures will bring developments which will affect positively consumers through the availability of wider choice of services, focusing on demand response and energy efficiency.

Table 7.b Persons affected by measures for Problem Area IV

Affected party	Measure		
	7.4. Facilitating supplier switching	**7.5. Comparison Tools**	**7.6. Improving Billing Information**
Member States	The preferred option may need to be transposed into national law, resulting in administrative impacts. Some Member States (e.g. BE, IT) have eliminated exit fees already, the latter reporting increased consumer trust as a result. Others with a relatively high preponderance of exit fees (NL, IE, SI) are likely to be more reserved, particularly in light of the fact that they may have relatively competitive markets already.	The preferred option will need to be transposed into national law, resulting in administrative impacts. However, some 13 Member States already have at least one independent CT run by a government or government-funded body. As these are free of conflicts of interest, we can assume they are likely to meet the accreditation criteria.	The preferred option will need to be transposed into national law, resulting in modest implementation costs.
National regulatory authorities (NRAs)	The preferred option would likely lead to additional stakeholder engagement and enforcement actions, resulting in increased administrative impacts to NRAs. However, any clarification and simplification of EU legal provisions may lead to greater ease of enforcement, and commensurate savings. In addition, improved consumer engagement would make it easier for NRAs to ensure the proper functioning of national (retail) energy markets they are charged with.	The preferred option would likely lead to additional stakeholder engagement and enforcement actions, resulting in increased administrative impacts. However, this would not necessarily be a role for the NRAs as an independent body might be assigned the task (e.g. GB where an independent auditor audits the CT). However, any strengthening of EU legal provisions should lead to a reduction in the number of consumer complaints. In addition, improved consumer engagement would make it easier for NRAs to ensure the proper functioning of national (retail) energy markets.	The preferred option would likely lead to additional stakeholder engagement and enforcement actions, resulting in increased administrative impacts to NRAs. However, improved billing clarity would make it easier for NRAs to ensure the proper functioning of national (retail) energy markets they are charged with.
Transmission System Operators (TSOs)	Not affected.	Not affected.	Not affected.
Distribution System Operators (DSOs)	Any change in consumer switching behaviour resulting from the preferred option would be reflected in switching operations, and their associated administrative impacts. However, as DSOs are regulated monopolies, these costs (or savings, if switching decreases) will eventually be passed through to end consumers.	Insofar as the measures lead to increased switching, this will result in increased administrative costs to DSOs. However, these costs will be passed through to consumers through network charges.	Not affected.
Suppliers	Most suppliers are unlikely to welcome measures to further restrict switching-related fees, as these limit their ability to tailor tariffs to different consumers. Some may also financially benefit from the increased 'stickiness' switching-related fees create amongst their consumer base. In addition, any change in consumer switching behaviour resulting from the policy options would be reflected in switching operations, and the associated administrative impacts to suppliers.	Industry associations (EURELECTRIC and Eurogas) have publicly supported consumer access to neutral and reliable comparison tools. In particular, increased reliability and impartiality in comparison tools may encourage new market entrants, thereby improving the likelihood of a level playing field. However, some suppliers are unlikely to welcome measures to certify comparison tools as this may have an impact on how and where their offers are published, and their ability to tailor tariffs to different consumers (in terms of cost, etc.). Some may also lose out financially if they are no longer able to influence the ranking of search results to promote certain offers; this applies both to energy suppliers and to CT providers. Insofar as the measures lead to increased switching, this will result in increased administrative costs to suppliers.	Most suppliers are unlikely to welcome EU legislation addressing the content or format of energy bills, as this limit their ability to tailor bills to different consumers. Some may also benefit from the low awareness amongst their consumer base of information that may be contained in bills, such as switching information, consumer rights, and consumption levels.
Comparison tool providers	Not affected.	More stringent requirements in terms of reliability and impartiality may increase their costs, as may the need for accreditation. However, such costs may be offset by an increase in sales due to improved trustworthiness of the comparison tool.	Not affected.

Affected party	Measure		
	7.4. Facilitating supplier switching	**7.5. Comparison Tools**	**7.6. Improving Billing Information**
End consumers	Some end consumers would benefit from contract exit fees (permitted in the preferred option) if such fees mean that suppliers are able to offer them lower prices or better levels of service. However, all consumers are likely to benefit from a complete ban on other switching-related fees (as per the preferred option), as well as greater transparency around any switching-related fees they may be charged. More generally, the majority of consumers would benefit from further restricting the use of switching-related charges. Such charges are a financial barrier to accessing better deals, disproportionately affect decision making, foster uncertainty on the benefits of switching, and reduce retail-level competition.	The preferred option would benefit many consumers, as the offers displayed would be more representative of the best ones (e.g. those offering the best value for money and the best service levels) available on the market. Asymmetric access to information would be reduced. Consumers would have greater trust in their ability to select the best offer through improvements in levels of service, and they would be better protected. They will be better able to make informed choices, and to benefit from the internal market.	Some end consumers would benefit from contract exit fees if such fees mean that suppliers are able to offer them lower prices or better levels of service. However, all consumers are likely to benefit from a complete ban on other switching-related fees, as well as greater transparency around any switching-related fees they may be charged. More generally, the majority of consumers would benefit from further restricting the use of switching-related charges. Such charges are a financial barrier to accessing better deals, disproportionately affect decision making, foster uncertainty on the benefits of switching, and reduce retail-level competition.

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Description of analytical models used

In order to perform the quantitative analysis for the various Problem Areas, most notably Problem Areas I and II, as well as for the evaluation of certain individual measures described in the Annexes, a number of specialized energy modelling tools were used. The selection of the modelling tool to be used in each case was made based on its ability to answer the specific questions raised in each Problem Area.

METIS

For assessing the benefits of specific market design measures and their effect to power system operation and market functioning, a new optimization software – METIS – was used, currently being developed for the Commission[16].

METIS was presented to the Member States' Energy Economists Group on April 5th 2016. The Commission will be eventually the owner of the final tool. For transparency reasons, all deliverables related to METIS, including all technical specifications documents and studies, are intended to be published on the website of DG ENER[17].

Global Description

METIS is an on-going project initiated by DG ENER for the development of an energy modelling software, with the aim to further support DG ENER’s evidence-based policy making, especially in the areas of electricity and gas. The software is developed by a consortium (Artelys, IAEW (RWTH Aachen University), ConGas, and Frontier Economics) and a first version covering the power and gas system has already been delivered to DG ENER.

It is an energy model covering with high granularity (geographical, time etc.) the whole European energy system for electricity, gas and heat. In its final version it should be able to simulate both system and markets operation for these energy carriers, on an hourly level for a whole year and under uncertainty (capturing weather variations and other stochastic events). METIS works *complementary* to long-term energy system models (like PRIMES and POTEnCIA), as it focuses on simulating a specific year in greater detail. For instance, it can provide hourly results on the impact of higher shares of intermittent renewables or additional infrastructure built, as determined by long-term energy system models.

Upon final delivery, METIS will be able to answer a large number of questions and perform highly detailed analyses of the electricity, gas and heat sectors. A number of

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

[17] Once operational, the envisaged link is expect to be the following: https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

topics will be possible to tackle with METIS for the whole EU and/or specific regions, like:

- The impacts of mass Renewable Energy Sources integration to the energy system operation and markets functioning (for one or all sectors);
- Cost-benefit analysis of infrastructure projects, as well as impacts on security of supply;
- Studying the potential synergies between the various energy carriers (electricity, gas, heat).

On the other hand METIS is not designed to answer (at least in its first stage) questions like:

- Optimal investment planning (capacity expansion) for the EU generation or transmission infrastructure;
- Impacts of measures on network tariffs and retail markets;
- Short-term system security problems for the electricity and gas system (requiring a precise estimation of the state of the network and potential stability issues);
- Flow-based market coupling and measures on the redesign of bidding areas;
- Any type of projection for the energy system.

Description of the Power Markets and System Models

The software replicates in detail market participant's decision processes, as well as the operation of the power system. For each day of the studied year, all market time frames are modelled in detail: day-ahead, intraday, balancing. Moreover METIS also simulates the sizing and procurement of balancing reserves, as well as imbalances.

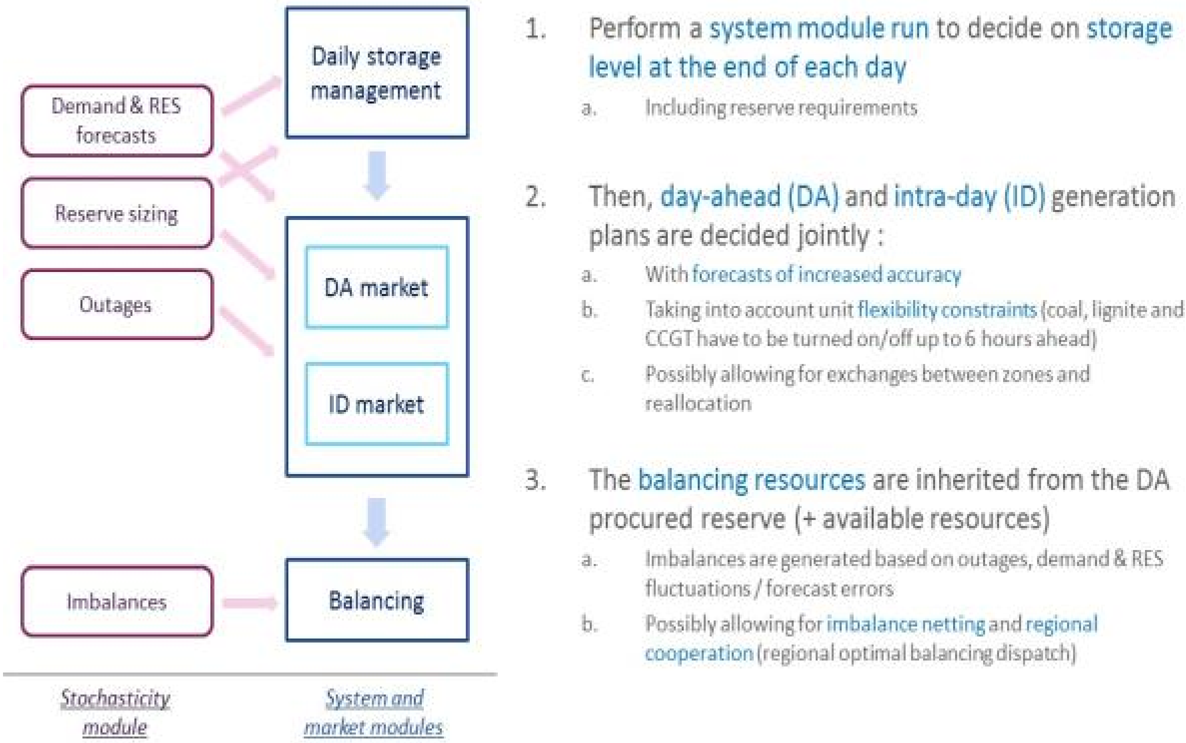
Uncertainties regarding demand and RES E power generation are captured thanks to weather scenarios taking the form of hourly time series of wind, irradiance and temperature, which influence demand (through a thermal gradient), as well as PV and wind generation. The historical spatial and temporal correlation between temperature, wind and irradiance are preserved.

Calibrated Scenarios – METIS has already been calibrated to a number of scenarios of ENTSO-E's Ten-Year Network Development Plan ('TYNDP') and PRIMES. METIS versions of PRIMES scenarios include refinements on the time resolution (hourly) and unit representation (explicit modelling of reserve supply at cluster and Member State level). Data provided by the PRIMES scenarios include: demand at Member State-level, primary energy costs, CO_2 costs, installed capacities at Member State-level and interconnection capacities.

Geographical scope – In addition to EU Member States, METIS scenarios incorporate ENTSO-E countries outside of the EU (Switzerland, Bosnia, Serbia, Macedonia, Montenegro and Norway) to model the impact of power imports and exports to the EU power markets and system.

Market models –METIS market module replicates the market participants' decision process. For each day of the studied year, the generation plan (including both energy generation and balancing reserve supply) is first optimized based on day-ahead demand and RES E generation forecasts. Market coupling is modeled via NTC constraints for interconnectors. Then, the generation plan is updated during the day, taking into account updated forecasts and asset technical constraints. Finally, imbalances are drawn to simulate balancing energy procurement.

Figure 1: Simulations follow day-ahead to real-time market decision process



Source: METIS

Reserve product definition – METIS simulates FCR, aFRR and mFRR reserves. The product characteristics for each reserve (activation time, separation between upward and downward offers, list of assets able to participate, etc.) are inputs to the model.

Reserve dimensioning – The amount of reserves (FCR, aFRR, mFRR) that has to be secured by TSOs can be either defined by METIS users or be computed by METIS stochasticity module. The stochasticity module can assess the required level of reserves that would ensure enough balancing resources are available under a given probability. Hence, METIS stochasticity module can take into account the statistical cancellation of imbalances between Member States and the potential benefits of regional cooperation for reserve dimensioning.

Balancing reserve procurement – Different market design options can also be compared by the geographical area in which TSOs may procure the balancing reserves they require. METIS has been designed so as to be able to constrain the list of power plants being able to participate to the procurement of reserves according to their location. The different options will be translated in different geographical areas in which reserves have to be procured (national or regional level). Moreover, METIS users can choose whether demand response and renewable energy are allowed to provide balancing services.

Balancing energy procurement – The procurement of balancing energy is optimized following the same principles as described previously. In particular, METIS can be configured to ban given types of assets, to select balancing energy products at national level, to share unused balancing products with other Member States, or to optimize balancing merit order at a regional level.

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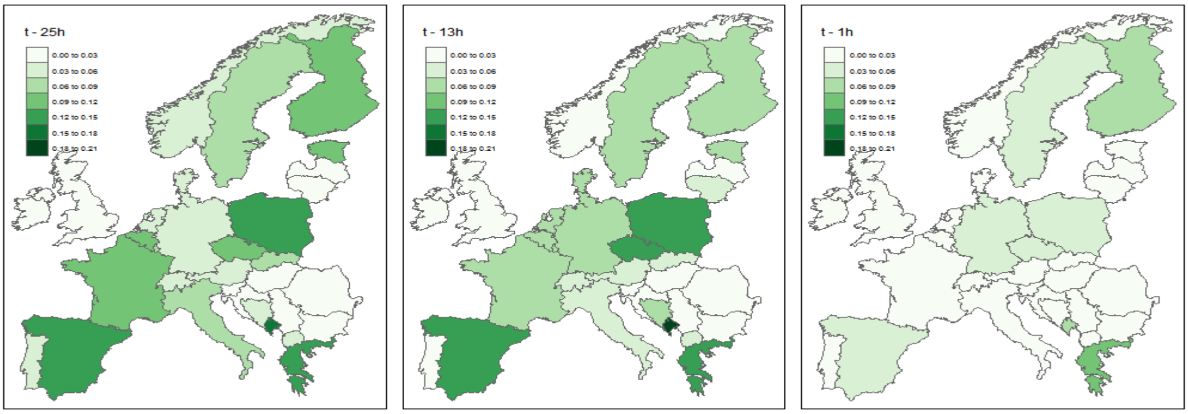
Imbalances – Imbalances are the result of events that could not have been predicted before gate closure. METIS includes a stochasticity module which simulates power plant outages, demand and RES E generation forecast errors from day-ahead to one hour ahead. This module uses a detailed database of historical weather forecast errors (for 10 years at hourly and sub-national granularity), provided by the European Centre for Medium-Range Weather Forecasts ('ECMWF'), to capture the correlation between Member State forecast errors and consequently to assess the possible benefits of imbalance netting. The stochasticity module will be further extended in the coming year to include generation of random errors picked from various probability distributions either set by the user or based on historical data.

Figure 2: Example of wind power forecast errors for a given hour of the 10 years of data.



Source: METIS

PRIMES suite of models

In order to assess the impacts of the various market design options on generator profits and investments, as well as the impact of capacity remuneration mechanisms and their different designs, a suite of models built by NTUA were used, with PRIMES model being at its core.

PRIMES

PRIMES[18] is a partial-equilibirum model of the energy system. It has been used extensively by the European Commission for settting the EU 2020 targets, the Low Carbon Economy and the Energy 2050 Roadmaps, as well as the 2030 policy framework for climate and energy.

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[18] http://ec.europa.eu/clima/policies/strategies/analysis/models/docs/primes_model_2013-2014_en.pdf.

PRIMES is a private model which has been developed and is maintained by E3MLab/ICCS of National Technical University of Athens[19] in the context of a series of research programmes co-financed by the European Commission. The model has been peer reviewed successfully, most recently in 2011[20].

The PRIMES model is suitable for analysing the impacts of different sets of climate, energy and transport policies on the energy system as a whole, notably on the fuel mix, CO2 emissions, investment needs and energy purchases as well as overall system costs. It is also suitable for analysing the interaction of policies on combating climate change, promotion of energy efficiency and renewable energies. Through the formalised linkages with GAINS non-CO_2 emission results and cost curves, it also covers total GHG emissions and total non-ETS sector emissions. It provides details on the Member State level, showing differential impacts across Member States.

Decision making behaviour is forward looking and grounded in micro-economic theory. The model also represents in explicit way energy demand, supply and emission abatement technologies, and includes technology vintages. The core model is complemented by a set of sub-modules modelling specific sectors. The model proceeds in five year steps and has been calibrated to Eurostat data for the years 2000 to 2010.

For the electricity sector, the PRIMES model quantifies projection of capacity expansion and power plant operation in detail by Member State distinguishing power plant types according to the technology type (more than 100 different technologies). The plants are further categorised in utility plants (plants with as main purpose to generate electricity for commercial supply) and in industrial plants (plants with as main purpose to cogenerate electricity and steam or heat, or for supporting industrial processes). The model finds optimal power flows, unit commitment and capacity expansion as a result of an inter-temporal non-linear optimisation; non-linear cost supply functions are assumed for all resources used by power plants for operation and investment, including for fuel prices (relating fuel prices non-linearly with available supply volumes) and for plant development sites (relating site-specific costs non-linearly with potential sites by Member State); the non-linear cost-potential relationships are relevant for RES E power possibilities but also for nuclear and CCS.

The simulation of plant dispatching considers typical load profile days and system reliability constraints such as ramping and capacity reserve requirements. Flow-based optimisation across interconnections is simulated by considering a system with a single bus by country and with linearized DC interconnections. Capacity expansion decisions depend on inter-temporal system-wide economics assuming no uncertainties and perfect foresight.

The optimisation of system expansion and operation and the balancing of demand and supply are performed simultaneously across the EU internal market assuming flow-based allocation of interconnecting capacities. The outcome of the optimisation is influenced by policy interventions and constraints, such as the carbon prices (which vary endogenously

[19] http://www.e3mlab.National Technical University of Athens.gr/e3mlab/.
[20] https://ec.europa.eu/energy/sites/ener/files/documents/sec_2011_1569_2.pdf'.

to meet the ETS allowances cap), the RES E feed-in tariffs and other RES E obligations, the constraints imposed by legislation such as the large combustion plant directive, constraints on the application of CCS technologies, policies in regard to nuclear phase-out, etc.

The optimality simulated by the model can be characterised either by a market regime of perfect competition with recovery of stranded costs allowed by regulation or as the outcome of a situation of perfectly regulated vertically integrated generation and energy supplying monopoly. This is equivalent of operating in a perfect way a mandatory wholesale market with marginal cost bidding just to obtain optimal unit commitment and a perfect bilateral market of contracts for differences for power supply through which generators recover the capital costs.

According to the model-based simulations, the capital costs of all plants, taken all together as if they belonged to a portfolio of a single generating and supplying company, are exactly recovered from revenues based on tariffs applied to the various customer types. This result does not guarantee that the optimal capacity expansion fleet suggested by the model-based projections cam be delivered in the context of more realistic market conditions with fragmentation and imperfections.

PRIMES was not directly used in this impact assessment, although the PRIMES EUCO27 setup was the basis for all analyses, with all inputs exogenous to the power sector, as well as generation capacities, coming from it. The main obstacle in using PRIMES for this impact assessment was that it assumes a perfectly competitive and well-functioning market.

For this scope two sub-modules closely linked to PRIMES were used instead:

- PRIMES/IEM is a day-ahead and unit commitment simulator, modelling the operation of the European electricity markets and system for a given year, being able to capture different market designs and market participant behaviours.
- PRIMES/OM is a variant of PRIMES, modifying the use of PRIMES in order to simulate investments under various competition regimes and with the possibility to capture the effect of CMs.

The two models are described below in more detail[21].

PRIMES / IEM

PRIMES/IEM aims at simulating in detail the sequence of power markets - Day-ahead, Intraday, Balancing and Reserve Procurement - in the EU for one year, covering all EU 28 Member States and their interconnections (also linked to non-EU European countries).

PRIMES/IEM is calibrated to PRIMES projections, taking as exogenous inputs:

[21] The detailed methodology followed, along with results, is described in a relevant report prepared for the scope of the impact assessment: "*Methodology and results of modelling the EU electricity market using the PRIMES/IEM and PRIMES/OM models", NTUA (2016)*

- Load (hourly);
- Power plant capacities (as projected) and their technical-economic characteristics, including old plants as available in projection period, new investments and refurbishments as projected by PRIMES;
- Fuel prices, ETS carbon prices, taxes, etc.;
- Resource availability for intermittent renewables;
- Interconnection capacities;
- Heat or Steam serving obligations of CHP plants having production of heat or steam as main purpose;
- Restrictions derived from policies, e.g. operation restrictions on old plants, renewable production obligations, if applicable, support schemes of renewables, biomass and CHP.

PRIMES/IEM disaggregates the interconnection network, considering more than one node per country, with connecting grids within the countries, in order to represent intra-country grid congestions. The assumptions about the grid within each country and across the countries change over time, reflecting an exogenously assumed grid investment plan. It also uses a more disaggregated hourly resolution than PRIMES, in representing load and availability of intermittent RES E resources, as well as more disaggregated technical and economic data for each plant than PRIMES, to represent cyclical operation of plants, possible shut-downs and start-ups. Finally, PRIMES-IEM uses detailed data on ancillary services (reserves) and the capability of plants to offer balancing services.

The day-ahead algorithm (GAMS program, written by E3MLab) is based on the EUPHEMIA[22] algorithm. The code runs for all countries and the user can select countries to simulate market coupling. The power plant capacities, demand (hourly for the days selected) and other information (e.g. grid) come from PRIMES database and projections. The linkage of data to PRIMES is fully automatic. The user can define rules for bidding by the plants, and the power plants (production hourly) which are 'must-take' and/or nominations. Available transfer capacities between countries can also be specified in the interface.

The unit commitment algorithm (GAMS program written by E3MLAB and solved as a mixed integer linear program) is a fully detailed plant operation scheduling algorithm. It includes the technical features of the power plants (technical minimum, minimum up-time, minimum down-time, ramp-up rates, ramp-down rates, time to synchronize, time to shut down and capability of providing ancillary reserve services to the system), the technical features of the interconnectors (applying DC linear power flows) and the reserve requirements of the system (primary, secondary, spinning tertiary, non-spinning tertiary and optionally ramping-flexibility reserves). The program runs simultaneously for the selected countries, which are assumed to operate under a coordinated-synchronized unit commitment. The program runs on an hourly basis and simultaneously for the sequence of typical days; runs fully one day having assumed next day, and so on.

[22] EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm) is the single price coupling algorithm used by the coupled European PXs (http://energy.n-side.com/day-ahead/).

The code is fully consistent with the unit commitment codes ran by TSOs in Europe and in the USA (compatible with the recommended code by FERC in the USA).

The day-ahead market Simulator (DAM_Simul) runs all EU countries simultaneously, solving market clearing by node (one node per country) and calculating interconnection flows restricted by DC power flows and by Available Transfer Capacities (defined by pair of countries).

Market participant bidding[23] is based on marginal costs plus mark-up reflecting scarcity. Must take CHP, RES and nominated capacities are included in DAM simulation as fixed (unchanged) hourly amounts. Similarly the reservation of cross-border capacity for nominations is fixed. In some policy-options these assumptions are relaxed. The wholesale prices of DAM are calculated from the relaxed problem, after having run the mixed integer problem. The DAM-Simulator runs pan-European and includes interconnection flows subject to limitations of power flow and NTC/ATC restrictions as applicable and if applicable in each policy option.

The unit commitment simulator (UC_Simul) includes exogenously defined reserve requirements, the outcomes of the event generator, the operation schedule of all units, the bids in DAM and penalty factors for slack variables (re-dispatching). Operation of small-RES E and must-take CHP is fixed. The unit commitment simulator runs pan-European limited by power flows and NTC values.The purpose of this run is to determine the deviations from DAM schedule, to be used in the intraday and balancing simulator.

The Intraday and Balancing Simulator (IDB_Simul) runs the above intraday and balancing market (once for 24-hours all together) and determines a price for deviations, the financial settlement of deviations and a revised schedule for operation of units and interconnectors.

In IDB_Simul, eligible resources can bid for supplying power to meet the deviations. The bids can differ for upward and for downward changes of power supplied by the eligible resources. Eligibility is defined specifically for each policy option. Capacity from interconnectors may be eligible but only if remaining capacities (beyond the schedule of the unit commitment) allow for this.

23 Bidding functions are defined by plant in DAM on the basis of the marginal fuel cost of the plant, increased by a mark-up defined hourly as depending on scarcity. The modelling of the bidding behavior of generators, similar in PRIMES/IEM and PRIMES/OM, is discussed in detail in the PRIMES/OM Section.

Figure 3: Modelling Sequence in PRIMES/IEM

Sequence of modelling of one day

1. Day-Ahead Market Simulation (DAM_Simul)
    - Plant operation schedule (DAM)
    - Financial settlement
2. Random Events Generator (REG)
    - Wind, Solar, demand, outages of plants and/or interconnections
3. Unit Commitment Simulator (UC_Simul)
    - Reserve requirements exogenous
    - Revised plant operation schedule (UCS)
    - Deviations of UCS from DAM
4. Intra-Day and Balancing Simulator (IDB_Simul)
    - Demand for deviations
    - Supply (eligible resources) and their bidding
    - Financial settlement
    - Revised plant availability
5. Reserve and ancillary services market and procurement Simulator (RAS_Simul)
    - Demand for reserves and ancillary services
    - Supply (eligible resources) and their bidding
    - Financial settlement
    - Revised plant availability
6. Unit Commitment Simulator (physical)
    - Plant operation
    - Plant costs
    - Emissions and fuel consumption

Source: PRIMES/IEM

In the Reserve and ancillary services procurement Simulator (RAS-Simul) demand for reserves is defined exogenously (equal to demand used in the UC_Simul). The outcome of RAS-Simul is the remuneration of the resources for providing reserves and a possible (small) modification of the schedule of units and interconnection flows.

For each policy option the demand for reserves is differentiated. Eligible resources can bid for supplying power to meet the demand for the different types of frequency reserves. Also, a subset of plants are eligible in each market for reserve. When the bids are endogenous and market-based, the prices include scarcity markups, with scarcity referring to the market for reserves. Eligibility of resources is defined differently for each policy option. Resources available cross-border can participate (differently constrained by policy option) in the markets for reserves subject to limitation from availability of interconnection capacity, which is the capacity remaining after the schedule of the unit commitment and intraday. Resources not scheduled after the unit commitment and the intraday can submit bids to the markets for reserves (only for tertiary reserve) but only gas turbines are eligible for this purpose.

For the finalisation of the simulation, the unit commitment simulator is run again assuming as given the schedule of units and interconnection flows resulted from previous steps and the load (hourly). The objective function includes only penalties for deviation from the schedule resulted from the previous step. The ascending order of penalties is RES E, interconnection flows, gas, solids, nuclear, demand or another order defined specifically by policy option. If must-take CHP and small-RES E can be curtailed then they are also included with penalties, otherwise they are fixed. The unit commitment simulator runs at this stage pan-European and applies flow based allocation of interconnections. The purpose of this run is to calculate the production by plant, consumption of fuel, operation cost by plant and emissions.

Demand response is modelled similarly to pumping transferring power from peak- to baseload; the amount of energy reduced in peak hours is compensated in the same day by additional energy consumption in other time segments, chosen endogenously. Therefore demand response bids for differential demand reduction and demand increase at different times, the bidding price reflecting costs (exhibiting decreasing return to scale), scarcity cost opportunity and the bidding quantity being subject to potential. Demand response (defined differently for each policy option) can be incorporated in all stages, i.e. DAM, intraday, reserves.

The simulation cycle closes by the reporting of financial balances (load payments, revenues and costs) for each generator, load and the TSO and calculating unit cost indicators (e.g. for reserves, etc.). As the simulation is stochastic, the expected values of the outcomes are calculated as the average of results by case of random events weighted by the frequency of the case.

PRIMES / OM

PRIMES/OM is a modified version of the power sector model of PRIMES, tailored to the needs of the impact assessment. It uses the PRIMES database, as well as its scenario assumptions. By departing from the usual perfect competition assumption of PRIMES, it can simulate investment behavior and the influence of CMs under various competition regimes and bidding behaviours. Simulations are dynamic, demand is price elastic and cross-border flows endogenous.

The model variant covers the power sector of all EU Member States linked together. The model simulates an organized wholesale market, calculating prices, revenues and costs, and estimating the probability of eventual mothballing of old plants and the cancelling (partially or entirely) of investment in new plants as a consequence of the revenues associated to the individual plant.

The model includes as an option a stylized CM auction, with or without cross-border participation, which is general in scope in terms of eligibility and covers all dispatchable generators. The inclusion or not of national CMs varies by scenario simulated. The model considers that the presence of a CM leads to lower risk premium factors which are used by generators to decide mothballing of old plants or cancelling of investments. However, the CM demand functions, as specified according to the logic of the model, are such that they may grant unnecessarily capacity payment to some plant categories.

Figure 4: Modelling Sequence in PRIMES/OM

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Sequence of investment modelling in PRIMES/OM

1. Define Context
    - Bidding Behavior (e.g. marginal cost, scarcity pricing)
    - Policy Scenario (in terms of GHG, ETS, RES Targets)
2. Starting point for investment is the most relevant PRIMES scenario
3. Simulate market operation under assumed generating capacities and bidding behavior
    - Day ahead market
    - Unit Commitment
4. In case CMs are assessed, include:
    - Design details of CM
    - Cross border specifications
5. Derive value of investment
    - Calculate degree of recovery of fixed costs
    - Derive Risk
6. Modify investment behavior
    - Based on real option theory
    - If CM are assessed, they are assumed to influence the risk
7. Repeat the sequence until convergence

Source: PRIMES/OM

The model runs dynamically from 2020 until 2050, in 5-year steps. It uses a full PRIMES model scenario as starting point, from where it takes the first input for load, renewables and the projection of power plant capacities. Subsequently it modifies load based on demand response, capacity availability and investment (except for renewables, industrial and district heating CHP) as a result of the mechanism described above.

A fundamental assumption of the oligopoly model is that the economics on which capacity-related decisions are made by generators are specified individually for each plant. However, the standard PRIMES model looks at the economics of portfolios of plants to determine the outcome of capacity-related decisions. It also, enables us to quantify the differences between market outcomes in perfect competition, where marginal cost bidding is applied, and under the oligopoly market structure where uplift is applied to the bids of market participants.

Main characteristics of PRIMES/OM

Investment Evaluation – A stochastic analysis is performed with respect to the main uncertainty factors affecting investments or early retirement of old plants, thus introducing a probability space for the simulation of investment decision under uncertainty. These factors have been identified as follows: (a) ETS carbon prices, (b) natural gas prices in relation to coal prices, and (c) the volume of demand for electricity net of renewables. In addition to the uncertainties pertaining to the framework conditions, the heterogeneity of decision makers in the investment evaluation process has also been taken into account. This is accomplished by considering a distribution probability of the hurdle rates that an investor considers (subjectively) for undertaking an investment. The hurdle rates are equivalent to the minimum Internal Rate of Return value for deciding positively upon an investment. The frequency distribution is modified in terms of mean and standard deviation dependent upon the certainty or lack thereof of revenues;

revenues coming from the energy only market compared to those coming from a CM imply higher mean and standard deviation of the distribution of hurdle rates.

Combining all of the above, a sample of about 100 combinations is generated around the EUCO27 trajectory for the three stochastic factors for the whole time period (as vectors over time) and 100 hurdle rate cases with combined probabilities. For the purposes of investment evaluation, the pan-EU energy-only market is run for each sample of the stochastic factors and revenues and costs for each plant are calculated for their total lifetime, including possible extension of operation. Two sources of revenues are accounted for: from operation in the energy-only market and from supplying reserve to the system. For the cost calculation, capital annuity payments were excluded. Using the revenues and costs calculated as such, the economic performance of each power plant is found, defined as the present value of future earnings above operation costs for each sample of uncertain factors and each hurdle rate case. The expected economic performance of a plant is the result of an average of performances weighted by the probabilities.

Heterogeneous decision makers, identified by the distribution of the hurdle rates as mentioned above, have a different threshold probability in order to decide whether or not to continue operating a plant or cancelling investment. In other words, there is an association of expected economic performance of each plant, as represented by its present value, with investment cost of new plants or with salvage value (remaining capital value) for plants, which are distributed across the decision makers according to a normal probability distribution function. Therefore, the frequency of decision about survival of a plant's capacity as a function of the economic performance indicator is used as the probability of survival. The capacity volume of the plant as projected by PRIMES in the context of the EUCO27 scenario multiplied by the probability of survival provides us with an update of the capacity volume.

Modelling of CMs – When a CM is assumed to be in place, it is modelled in a stylized manner. All capacities are eligible, if dispatchable, including hydro lakes and storage, provided that they are not under a different support scheme. For example, CHP, biomass, etc. are excluded. Also, plants in the process of decommissioning or operating few hours per year due to environmental restrictions as projected in PRIMES are excluded. All capacities are remunerated for the available capacity excluding outages.

The CM payment is a result of an auction. The CM price is derived from the intersection of demand for capacity and the offers, sorted in ascending price order. Demand for capacity is defined as a negative-sloped linear line depending upon a price cap and linking two capacity points: the minimum and maximum requirements. For all capacity offered up to the minimum requirement the auction clearing price is equal to the price cap, while for the maximum requirement it is equal to zero. The definition of the demand curve takes into account trusted imports at peak load times and the guaranteed proportion of exports. Therefore, implicit participation of flows over interconnections is taken into account. Cross-border participation, when applicable, increases capacity offering. Removal of capacities (due to mothballing or cancelling of investment, or because the capacity is offered to a foreign CM) also decreases capacity offering. The CM winners sign a reliability option (one way option) which has a strike price. If the wholesale market price is above the strike price they are assumed to return the revenues above strike price. The results of the CM auctions, namely the stream of revenues they provide to generators, are taken into account by the oligopoly model in the final step of investment evaluation.

Bidding Behaviour - The model assumes a scarcity bidding function as a means to mimic the strategic behaviour of market players in an oligopoly. The bidding function is specific to each individual plant and it takes into account hourly demand, plant technology and plant fixed costs in order to evaluate the hourly bid price of each generator.

In order to model the bidding behaviour of plants, they are assigned to one of four different types of merit order: no-merit, baseload, mid-load, and peak load. Hydro-reservoirs consider also water availability. The assignment of plants takes place based on their technology as well as on whether they participate in the energy only market; non-dispatchable generators are considered as must-take, and therefore are assumed to bid at zero price. The no-merit order type is intended to include this type of plants. The baseload category includes mainly nuclear and coal/lignite plants, the mid-load CCGTs, and the peak load of GTs and Reservoir Hydro.

Subsequently, the capacities of all plants within a merit order type are summed up in order to determine the total capacity of every type, developing a merit stack. Then the hourly demand is compared with the merit stack in order to estimate for every hour which merit order type is expected to be on the margin. This is the type on which a scarcity mark-up will be applied, assuming this is the market segment in which all strategic behaviour of market participants takes place for a specific hour. The marginal cost which sets the basis for the price at which each plant offers its energy is calculated based on variable cost data from the PRIMES database. The mark-up is calculated based on the following equation:

$$SB_p = MC_p + CEIL_m * \mathrm{e}^{-\mathbf{RATE}_p \cdot \left[\frac{\mathbf{SUPP}_m}{\mathbf{DEMD}_m} - 1\right]}$$

P is the plant identifier, M the merit order type, MC the Marginal cost, $SUPP$ the total supply (capacity) of merit order type, $DEMD$ the hourly demand specific to merit order type, $CEIL$ the price ceiling for merit order type, $RATE$ the (inverse) rate of mark-up and SB the scarcity bid. The demand specific to a generation type is calculated as the residual of hourly demand minus the capacity of the merit order types which lie below the marginal.

The price ceiling is specific to every merit order type and is applied in order to guarantee that the merit order is never reversed, i.e. peak load plants being dispatched before mid-load plants, mid-load before baseload, etc. Also, the rate specific to each plant is dependent upon the fixed costs of the plant, which comprise mainly of capital costs, in a risk averse manner. This convention is in place so that plants with high fixed costs are more reluctant to apply a mark-up to their marginal cost in fear of staying out-of-merit and not being dispatched due to the mark-up being too high. Finally, if in post-calculation the scarcity bid exceeds the price ceiling, it is set equal to the ceiling.

Description of methodological approach followed concerning baseline

PRIMES EU Reference Scenario 2016

A common starting point to all Impact Assessments is the EU Reference Scenario 2016 ('REF2016'). It projects greenhouse gas emissions, transport and energy trends up to 2050 on the basis of existing adopted policies at national and EU level and the most recent market trends. This scenario was prepared by the European Commission services in consultation with Member States. All other PRIMES scenarios build on results and modelling approach of the REF2016.

Although REF2016 presents a comprehensive overview of the expected developments of the EU energy system on the basis of the current EU and national policies, and could be considered as the natural baseline for all impact assessments, it fails doing so for an important reason. This scenario does not have in place the policies to achieve the 2030 climate and energy targets that are already agreed by Member States in the European Council Conclusions of October 2014. It also does not reflect the European Parliament's position on these targets.

Therefore, although it was important for all initiatives to have a common "context" in order to ensure coherent assessments, each Impact Assessment required the preparation of a specific baseline scenario, which would help assess specific policy options relevant for the given Impact Assessment.

Central Policy Scenario: PRIMES EUCO27

Because of the need to take into account the minimum agreed 2030 climate and energy targets (and the 2050 EU's decarbonisation objectives) when assessing policy options for delivery of these targets, a central policy scenario was modelled ('EUCO27').

This scenario is the common policy scenario for all Impact Assessments. Additional baseline and policy scenarios were prepared for each Impact Assessment, addressing the specific issues to be assessed by each initiative, notably which measures or arrangements have to be put in place to reach the 2030 targets, how to overcome market imperfections and uncoordinated action of Member States, etc. A summary of the approach followed in each respective impact assessment can be found in the Annex IV of the RED II impact assessment.

This approach of separating a central policy scenario reaching the 2030 targets in a cost-effective manner and other scenarios that look into specific issues related to implementation of cost effective policies enables to focus on "one issue at a time" in the respective separate analysis. It enabled to assess in a manageable manner the impacts of several policy options and provide elements of answers to problem definitions listed in the 2016 impact assessment, without the need to consider the numerous possible combinations of all the options proposed under each respective initiative.

PRIMES EUCO27 scenario is based on the European Council conclusions of October 2014[24]. In particular, the following were agreed among the heads of states and governments:

- Substantial progress has been made towards the attainment of the EU targets for greenhouse gas emission reduction, renewable energy and energy efficiency, which need to be fully met by 2020;
- Binding EU target is set of an at least 40% domestic reduction in greenhouse gas emissions by 2030 compared to 1990;
- This overall target will be delivered collectively by the EU in the most cost-effective manner possible, with the reductions in the ETS and non-ETS sectors amounting to 43% and 30% by 2030 compared to 2005, respectively;

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

- A well-functioning, reformed ETS with an instrument to stabilise the market in line with the Commission proposal will be the main European instrument to achieve this target; the annual factor to reduce the cap on the maximum permitted emissions will be changed from 1.74% to 2.2% from 2021 onwards;
- An EU target of at least 27% is set for the share of renewable energy consumed in the EU in 2030. This target will be binding at EU level;
- An indicative target at the EU level of at least 27% is set for improving energy efficiency in 2030 compared to projections of future energy consumption based on the current criteria. It will be delivered in a cost-effective manner and it will fully respect the effectiveness of the ETS-system in contributing to the overall climate goals. This target will be reviewed by 2020, having in mind an EU level of 30%;
- Reliable and transparent governance system is to be established to help ensure that the EU meets its energy policy goals, with the necessary flexibility for Member States and fully respecting their freedom to determine their energy mix;

The above requirements, with a minimum energy saving level of 27%, are reflected in EUCO27. Concrete specifications on assumptions were made by the Commission in order to reach the relevant targets by using a mix of concrete and yet unspecified policies. A detailed description of the construction of this scenario is presented in Section 4 of the EE impact assessment and its Annex IV.

As this scenario is not directly used in the present impact assessment, the reader is referred to the relevant technical annexes of the EE and RED II impact assessments for more details on its main assumptions and results. Table 1 below presents the main projections for 2030 related to the power system for EU28.

Table 1: PRIMES EUCO27 Modelling Results for the power system (EU28)

	2000	2015	2030	Share in total for 2030 (%)	% diff 2015-2010	% diff 2030-2015
Electricity consumption (in TWh)	**3,029.0**	**3,271.8**	**3,525.6**		8%	8%
Final energy demand	2,530.7	2,802.4	3,081.3		11%	10%
Industry	1,061.1	1,001.4	1,054.8	30%	-6%	5%
Households	713.8	833.6	899.7	26%	17%	8%
Tertiary	683.5	899.3	982.2	28%	32%	9%
Transport	72.3	68.2	144.6	4%	-6%	112%
Energy branch	281.7	262.6	231.2	7%	-7%	-12%
Transmission and distribution losses	216.2	206.7	213.1	6%	-4%	3%
Net Installed Power Capacity (in GW_e)	**683.5**	**965.6**	**1,131.0**		41%	17%
Nuclear energy	139.6	120.8	109.9	*10%*	-13%	-9%
Renewable energy	129.0	366.7	652.2	*58%*	184%	78%
Hydro (pumping excluded)	115.8	127.5	133.3	12%	10%	5%
Wind on-shore	12.7	130.6	246.1	22%	-	88%
Wind off-shore	0.1	11.0	37.9	3%	-	246%
Solar	0.2	97.4	233.8	21%	-	140%
Biomass-waste fired	12.7	27.9	53.1	5%	121%	90%
Other renewables	0.8	1.1	2.1	0%	32%	86%
Thermal power	414.9	478.1	368.9	*33%*	15%	-23%
Solids fired	194.5	176.6	99.4	9%	-9%	-44%
Oil fired	83.3	53.1	15.3	1%	-36%	-71%
Gas fired	123.8	219.6	200.1	18%	77%	-9%
Net Electricity generation by plant type (in TWh)	**2,844.0**	**3,090.0**	**3,396.7**		9%	10%
Nuclear energy	893.9	825.7	738.4	*22%*	-8%	-11%
Renewable energy	374.5	736.2	1,372.8	*40%*	97%	86%
Hydro (pumping excluded)	351.6	357.7	375.1	11%	2%	5%
Wind on-shore	22.2	241.4	564.4	17%	-	134%
Wind off-shore	-	32.8	127.3	4%	-	288%
Solar	0.1	103.8	303.6	9%	-	193%
Biomass-waste fired	42.9	130.6	238.1	7%	204%	82%
Other renewables	5.0	7.1	9.7	0%	42%	37%
Thermal power	1,575.6	1,528.0	1,285.6	*38%*	-3%	-16%
Solids fired	866.3	780.3	448.6	13%	-10%	-43%
Oil fired	178.4	30.2	14.6	0%	-83%	-52%
Gas fired	483.4	580.4	576.8	17%	20%	-1%

Source: PRIMES

Baseline: Current Market Arrangements ('CMA')

The Market Design Initiative addresses four different Problem Areas. The first two, addressing market functioning and investments, share a common baseline which is highly dependent on the context (e.g. based on REF2016 or EUCO27). The other two Problem Areas, concerning risk preparedness and retail markets, are more independent of the overall context, as in each case the envisaged baseline and options can apply in either context (moreover the assessment tends to be mainly qualitative). Therefore the discussion on the baseline is meaningful mainly for the first two Problem Areas.

Similar to the other 2016 Energy Union initiatives, EUCO27 was chosen as the starting point (i.e. context) of the baseline for the Market Design Initiative (so-called "Current Market Arrangements" – CMA). The EUCO27 scenario is the most relevant to the objectives of the initiative, as it provides information on the investments needed and the power generation mix in a scenario in line with the EU's 2030 objectives.

As all analysis focuses on the power sector, all assumptions exogenous to the power sector were taken from the EUCO27 scenario. This also applied for the energy mix, the power generation capacities for each period, the fuel and carbon prices, electricity demand, technology costs etc. The main obstacle in further using the EUCO27 as a baseline for this impact assessment was that it assumes a perfectly competitive and well-functioning European electricity market, more matching the end point than the starting point of the analysis. Therefore CMA differs from the EUCO27 scenario by including existing market distortions, as well as current practices and policies on national and EU level.

The CMA assumes implementation of the Network Codes, including the CACM and the EB Guidelines (the later in their proposed form). It is assumed that the CACM Guideline will bring a certain degree of harmonisation of cross-border intraday markets, gate closure times and products for the intraday, as well as a market clearing. National intraday and balancing markets will be created across EU and a certain degree of market-coupling of intraday markets will be achieved. At the same time, the EB Guideline is expected to bring certain improvements to the balancing market, namely the common merit order list for activation of balancing energy, the standardisation of balancing products and the harmonisation of the pricing methodology for balancing. Nonetheless, other important areas like harmonisation of intraday markets and balancing reserve procurement rules will not be affected by the guidelines.

The baseline does not consider explicitly any type of existing support schemes for power generation plants, neither in the form of RES E subsidies nor in the form of CMs[25]. This is governed to a large degree from the 2014 EEAG applicable as of 1 July 2014. Aid schemes existing at that moment have to be amended in order to bring them into line with EEAG no later than 1 January 2016. This with the exception of schemes concerning operating aid in support of energy from renewable sources and cogeneration that only need to be adapted to the EEAG when Member States prolong their existing schemes, have to re-notify them after expiry of the 10 years-period or after expiry of the validity of the Commission decision or change them. This implies that all existing schemes will expire by 2024 at the latest and will be adapted to the EEAG, applicable at the time of their notification. Current guidelines allows operational aid only as feed-in premium, not attributed for the hours with negative prices and with its level determined via tenders. In essence this means that non-market based support schemes are fully phased out by 2024 assuming that the rules as regards RES E and CHP aid schemes well remain unaltered when the EEAG is reviewed in 2020.

[25] Admittedly this assumption is strong, but necessary to simplify the analysis. Otherwise a riskier (for the analysis) assumption would need to be made on the future share, type and level of support for the various support schemes per Member States in the end becoming a major driver for the results and complicating their interpretation.

Moreover, the RED II proposals (part of the baseline of the present impact assessment) will enshrine and reinforce the market-based principles for the design of support schemes. As it is reasonable to assume that the RED II will enter into force prior to 2024, assuming that all support to RES E by 2030 is market based is a prudent assumption.

The effect of RES E subsidies is relevant to the MDI impact assessment only when it directly affects the merit order. Overall the cost-efficient level of investments in RES E[26] is taken as given across all assessed options, as projected in EUCO27, without examining how the costs of these investments are recuperated (topic addressed in the RED II impact assessment). The baseline assumes one of the main objectives of the RED II initiative is achieved and a framework strengthening the use of tenders as a market-based phase-out mechanism for support is in place, gradually reducing the level of subsidies over the course of the 2021-2030 period (still support schemes would exist for all non-competitive RES E technologies). Moreover it is assumed that existing FiT contracts have been phased-out by 2030 to a large degree, most importantly the ones targeted on biomass, being the ones most distorting to the merit order. As a result the assumption of not considering any non-market based support for RES E generation is reasonable and not significantly affecting the results.

As for CMs, existing or planned, they are mainly relevant for Problem Area II and did not need to appear in the common baseline of the two Problem Areas. The analysis for Problem Area I did not touch issues related to investments, thus the assumption of CMs (which would be present in all assessed options) would have a limited influence on the impacts and the ranking of the options[27]. As far as Problem Area II is concerned, again their inclusion was avoided, as any results would be highly dependent on the specific CM assumptions over the examined period. Moreover, in line with the results of the analysis in section 6.2.6.2, the effect of adding a CM would most likely be to further increase the cost of the power system. As the baseline was already a very costly scenario compared to the preferred energy-only market one, the conclusion from the comparison of the options would remain the same.

METIS calibration to EUCO27

As mentioned above, for the scope of this impact assessment METIS was calibrated to the PRIMES EUCO27 scenario. In fact, as the calibration needed to take place much before the finalisation of the PRIMES EUCO27, it was performed on one of its preliminary versions. The main elements of the calibration process, as well as the most important differences between the preliminary and the final version of EUCO27 are described below. A significantly more detailed description of the calibration has been reported on a separate document, to be found on the METIS website[28].

Preliminary EUCO27

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26 The same applies for CHP, when the main use of those plants is the production of heat/steam.

27 The CMs would not affect the merit order in problem area I, as the analysis assumes bidding based on marginal costs (not scarcity pricing, which is introduced in problem area II).

28 Once operational, the envisaged link is expect to be the following: https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

The two versions of EUCO27 are in general quite close from an EU energy system perspective. Two differences can be found in 2030, one in the RES E shares and the other in CO2 prices, slightly affecting power generation capacities and production.

RES E overall share is in both cases 27%, with a differentiation in the sectoral contribution: in the preliminary version the share of RES E is at 48.4%, while being 47.3% in the final EUCO27 version. This was mainly driven by differences in off-shore wind deployment. There is more switching from coal to gas in the final version. This is translated to 2 p.p. increase of gas in the share of power gas generation, while solids decreased by 0.5 p.p. and RES E by 1.3 p.p.. The CO_2 price, which was 38.5 EUR/tCO_2 in the preliminary version is 42 EUR/tCO_2 in the final EUCO27 version.

The effect of these differences is not very significant on the EU level, although it does have some implication on the results of specific Member States with a projected high capacity of off-shore wind in the preliminary version, e.g. the UK.

METIS calibration to PRIMES EUCO27

For the scope of this impact assessment, simulations adopted a country level spatial granularity and an hourly temporal resolution of year 2030 (8760 consecutive time-steps year), capturing also the uncertainty related to demand and RES E power generation. Modelling covered all ENTSO-E countries, not only EU Member States, as follows:

- All ENTSO-E countries for the day-ahead market;
- EU28+NO+CH for intraday, balancing and reserve procurement[29];
- EU28+NO for regional co-operation for reserve procurement, CH reserve assumed to be procured nationally.

For configuring METIS to match the (preliminary) PRIMES EUCO27 projections, a number of steps were taken, the most important of which are described in the following. Details can be found in the relevant METIS report[30].

1. The data provided for the calibration concerned only EU28. Missing data for other countries modelled with METIS (i.e. Bosnia, Switzerland, Montenegro, FYROM, Norway and Serbia) were complemented by other sources, mainly ENTSO-E 2030 vision 1 of TYNDP 2016.
2. The hourly power demand time series were based on ETNSO-E's 2030 vision 1 scenario. Data were adjusted so that on average (over 50 weather data realizations) the power demand of each country corresponds to the PRIMES EUCO27 projections.
3. Installed capacities were computed based on PRIMES EUCO27 scenario[31]. For certain EU28 countries the split between hydro lake and run-of-river of PRIMES

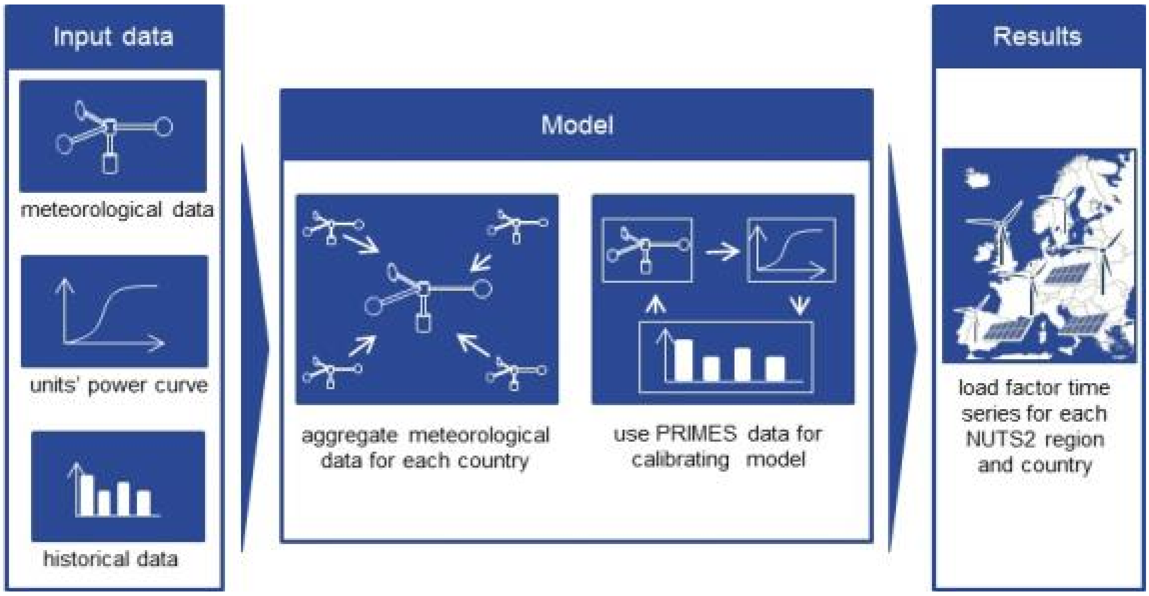
[29] Actually reserve procurement was not modelled for other non-EU28 Member States, as well as for Malta, Cyprus and Luxembourg.

[30] "*METIS Technical Note T04: Methodology for the integration of PRIMES scenarios into METIS*", Artelys (2016)

was reviewed based on historical data form ENTSO-E, due to differences in the definitions used in PRIMES (based on Eurostat) and METIS (based on ENTSO-E).

4. Generation of ten historical yearly profiles for wind and solar power was performed according to the methodology depicted in Figure 5. The methodology followed delivered annual load-factors closely matching the ones of PRIMES EUCO27.

Figure 5: PV and wind generation profiles



Source: METIS

5. Thermal plant fleets comprised of the following technologies: hard coal, lignite, CCGT, OCGT, oil, biomass. The various fleets, except oil and biomass, were divided into two or three classes (only CCGT were divided into three). Thermal installed capacities were based on PRIMES EUCO27, without though enforcing any type of constraint on the net electricity generation of these plants (which was a pure result of the modelling). The technical-economic assumptions of PRIMES were used for the power plants, complemented by other sources or databases when missing.
6. Water inflow profiles, as well as storage parameters, required important reconciliation work combing data from ENTSO-E, TSOs and PRIMES.
7. The international fuel price assumptions of PRIMES EUCO27 were used for calculating the marginal production costs of the thermal fleets. Specifically for coal and biomass, end-user fuel prices coming again from PRIMES EUCO27– including also transportation costs – were used instead.

[31] CHP units were treated as electricity-only gas plants, as currently METIS does not model the heat sector. Division of RES to small and large scale (e.g. rooftops solar) was also not captured.

8. METIS used the same NTC values as in PRIMES EUCO27[32]. NTC values between European and non-European countries are completed using ENTSO-E 2030 v1 scenario.
9. As METIS focuses in particular on the economics of security of supply, a key point is that installed capacity is consistent with peak demand. Consequently, provided OCGT capacities were optimized to satisfy security-of-supply criteria. To optimize OCGT capacities, supply-demand equilibrium was computed with “State of the art” OGCT capacities as variables over 50 years of weather data. Capacities of “oldest” OCGT fleets remain fixed to the installed capacities in 2000 which have not been replaced by 2030. Table 2 presents the results of the OCGT capacity optimization consisting in the added OCGT installed capacities per country. These additional capacities are added to the installed capacities in 2030 excluding the investment between 2000 and 2030.

Table 2: Additional OCGT capacities needed to satisfy security of supply standards

	BE	DK	FI	FR	IE	NO	SE	UK
OCGT added capacity (GW)	5	2	4	6	1	4	3	19

Source: METIS, Artelys Crystal Super Grid

METIS policy scenarios for the options of Problem Area I

This section provides information on the market design options that were modelled and assessed using METIS. Each scenario was run using the full capabilities of METIS. In fact certain aspects of METIS were further developed in order to be possible to better assess a number of the measures covered in the impact assessment.

Each scenario was intended to match the setup of one assessed option. For this purpose the options were first decomposed into a number of "fields", reflecting existing market distortions or design features that were addressed within each option. Following subsequent analysis, these fields were then narrowed down to the twelve presented in Table 3 below. For each of these fields, two or three sub-options were considered across the different scenarios. The sub-options considered (entitled "a"/""b"/"c") are identified on the right had columns of Table 3, while their description is provided in Table 4.

For all fields, sub-option "a" reflects current practices and existing market distortions, as well as the possible evolution of markets in the near future in the absence of new policies. The identification and methodology for the quantification of current practices was supported by a study performed specifically for this purpose[33].

[32] - Regarding grid development and the interconnectors between countries, they are based on the ENTSO-E TYNDP, following the respective timelines. After the end of the TYNDP, expansions are based on known plans and the development of RES E.

[33] "*Electricity Market Functioning: Current Distortions, and How to Model their Removal*", COWI (2016).

Table 3: Overview of MDI impact assessment Problem Area I scenarios as modelled by METIS (read in conjunction with Table 4)

Action	Field	MDI options				
		0	1(a)	1(b)	1(c)	2
1	DR deployment	a	b	b	c	c
2	RES E priority dispatch	a	b	b	b	b
3	Biomass reserve procurement	a	b	b	b	b
4	Coal/lignite unit commitment at intraday	a	b	b	b	b
5	Balance responsibility	a	b	b	b	b
6	Intraday coupling	a	a	b	b	b
7	Time granularity for reserve sizing	a	a	b	b	b
8	Reserve procurement methodology	a	a	b	b	b
9	Joint/separate upward/downward reserve	a	a	b	b	b
10	Use of NTC	a	a	b	b	c
11	Reserve dimensioning and risk sharing	a	a	b	b	c
12	PV, Wind and RoR reserve procurement	a	a	a	b	b

Source: METIS

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Annex IV: Analytical models used in preparing the impact assessment.

Table 4: Overview of the sub-options for each measure modelled in METIS

Measure	Topic	Description of the options
1	DR deployment	Three levels of DR deployment (sub-options a, b and c, with increasing economic potential, based on COWI BAU and PO2 scenarios[34]) were considered. In sub-option "a" DR can considered only for countries where DR has currently access to the market and only for industrial resources based on BAU potentials. In sub-option "b" DR by industrial resources appears in all countries based on BAU potentials. In sub-option "c" all DR resources participate based on the potential of the PO2 scenario, adjusted to better match EUCO27 projections and the activation limits of DR potential.
2	RES E priority dispatch	Two options were considered: a. Penalty factor for PV and Wind curtailment, priority dispatch for Biomass b. No penalty factor or priority dispatch for PV, Wind and Biomass For sub-option "a", modelling RES E priority dispatch for wind and PV was performed via a penalty factor and not by explicit priority dispatch. The reason was that there were a number of hours for certain Member States that if an explicit priority dispatch was enforced for all RES E, their power system collapsed (solution was infeasible). In reality this would most likely be addressed by the TSOs via the curtailment of RES E.
3	Biomass reserve procurement	Two options for participation of biomass in reserve procurement: a. Biomass does not participate in FCR or FRR b. Participation of Biomass (the absence of priority dispatch is a prerequisite)
4	Coal/lignite unit commitment at intraday	Two options for coal and lignite unit commitment: a. The day-ahead unit commitment decision (i.e. which plants are turned on or off) for coal and lignite power plants cannot be refined during intraday, i.e. coal and lignite plants are treated as must-runs in intraday once scheduled in day-ahead. b. Coal and Lignite can re-optimise their commitment in intraday (subject to their technical constraints).
5	Balance responsibility	By making RES E producers financially responsible for the imbalances they are encouraged to improve their generation forecasts. Two options were considered: a. H-2 forecasts were used for Wind and PV generation for reserve dimensioning and generation of imbalances. b. H-1 forecasts were used for demand and PV, while 30 min forecasts were used for Wind, leading to lower imbalances and lower reserve requirements.

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

Measure	Topic	Description of the options
6	Intraday coupling	Auctions for interconnections capacity can either be explicit, captured in METIS as if assuming the flows are fixed in H-4, or implicit, in which case flows can be updated in H-1. Two options were considered: a. Auctions were mostly explicit, except in specific areas based on current practices. b. Auctions were implicit for all interconnections. In any case, the reserve procured at day-ahead remained fixed during intraday.
7	Time granularity for reserve sizing	Two options were considered for aFRR reserve sizing: a. Fixed reserve size computed as 0.1% and 99.9% centiles of imbalance distribution over the year. While some Member States have different reserve sizes depending on demand variation, this option assumes that the reserve size is constant over the year for all Member States. b. Variable reserve size depending on the hour of the day and wind energy generation. Size is computed with 0.1% and 99.9% centiles of imbalance conditional distribution
8	Reserve procurement methodology	Reserve can be procured either day-ahead (which was modelled in METIS as a joint optimization of power and reserve hourly procurement at day-ahead) or on a fixed basis per year (in which case the mean annual value of optimal reserve procurement is used). The options were: a. Current practices b. Day-ahead procurement
9	Joint/separate upward/downward reserve	Two options were considered for upwards and downwards reserve: a. Joint procurement according to current practices b. Being two separate products which can be procured independently
10	Use of NTC	To model the process of interconnection allocation, three options were considered: a. National TSOs need to have a high security margin. For the scope of METIS, EUCO27 NTCs were reduced by 5%. b. Collaboration between TSOs reduces the need for security margins. EuCo NTC values were used. c. The introduction of a supranational entities will result in a further reduction of the security margins, leading to an increase by 5% of the EuCO NTCs.
11	Reserve dimensioning and risk sharing	To assess whether risk sharing can reduce the needs for national reserves, three options were considered. Reserve was sized using a probabilistic approach: a. At national level b. At regional level c. At EU level In order to ensure Member States can face similar security of supply risks when less reserves can be procured (Options b. and c.), part of the interconnections' capacity was reserved for mutual assistance between Member States.
12	PV, Wind and RoR reserve procurement	Two options: a. PV, Wind and Hydro RoR do not participate in FCR or FRR b. Participation of PV, Wind and Hydro RoR in FCR or FRR

Source: METIS

A more detailed description of the scenarios, how each option/measure was modelled and what were the identified relevant current practices, can be found in an explanatory technical report[35].

It is important to highlight that the scenarios under Problem Area I do not consider explicitly the possible existence of capacity mechanisms nor support schemes for RES E, focusing strictly on the wholesale market operation over the various time frames (day-ahead, intraday, balancing). Nevertheless, certain assumptions (like priority dispatch for biomass) would make economic sense only in the case of existing economic subsidies.

Figure 6: Regions used for cooperation in reserve sizing and procurement

Region 1
Austria
Belgium
Czech Republic
Denmark
France
Germany
Hungary
Luxembourg
Netherlands
Poland
Slovakia
Slovenia
Switzerland

Region 3
United Kingdom
Ireland

Region 4
Portugal
Spain

Region 2
Estonia
Finland
Latvia
Lithuania
Norway
Sweden

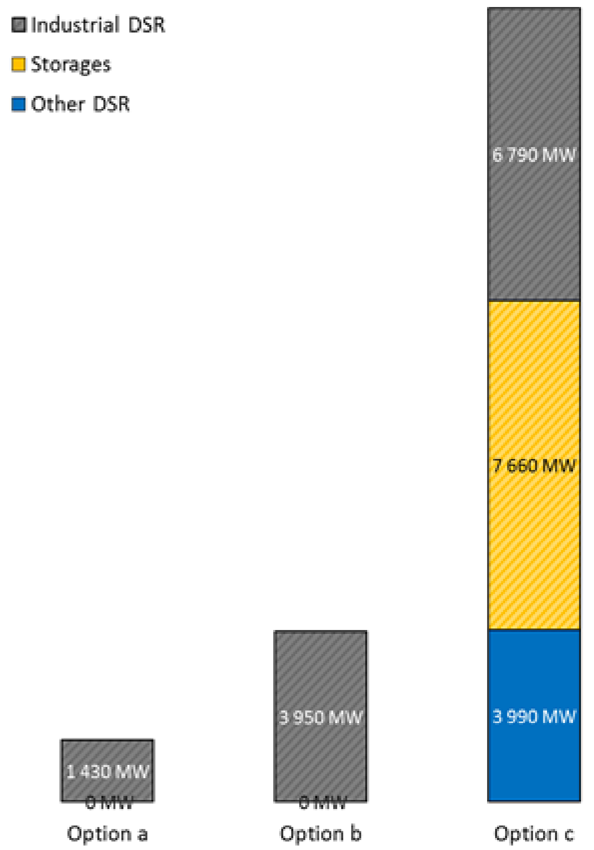
Region 5
Bosnia and Herzegovina
Bulgaria
Croatia
Cyprus
FYR of Macedonia
Greece
Italy
Malta
Montenegro
Romania
Serbia

Source: METIS

[35] "*METIS Technical Note T05: METIS market module configuration for Study S12: Focus on day-ahead, intraday and balancing markets*", Artelys and THEMA Consulting (2016).

Figure 7: DR deployment in METIS for options a, b and c and current practices in DR participation in balancing markets

DSR participation in balancing markets	FCR/aFRR	mFRR
Austria	yes	yes
Belgium	NA	yes
Bulgaria	yes	yes
Croatia	no	no
Czech Republic	no	no
Denmark	yes	yes
Estonia	no	no
Finland	yes	yes
France	N/A	yes
Germany	yes	yes
Greece	no	no
Hungary	no	no
Ireland	no	no
Italy	no	no
Latvia	no	no
Lithuania	no	no
Netherlands	yes	yes
Norway	yes	yes
Poland	no	no
Portugal	yes	yes
Romania	no	no
Slovenia	N/A	no
Slovakia	no	no
Spain	no	no
Sweden	yes	yes
Switzerland	yes	yes
United Kingdom	N/A	yes



Source: METIS

PRIMES/IEM policy scenarios for the options of Problem Area II

PRIMES/IEM scenarios were setup very similarly to the METIS scenarios. As can be deduced from the description of the model, PRIMES/IEM puts more emphasis on the simulation of the bidding behaviour of market participants and the modelling of the grid, thus making it a better tool to capture the additional measures considered in Option 1 of Problem Area II (on top of Option 1(c) of Problem Area I), i.e. the removal of low price caps and the addition of locational price signals.

The consideration of market participant bidding behaviour and internal grid congestion, made it necessary to re-run the baseline (Option 0) also of Problem Area I under these new assumptions, in order to be used as the baseline of Problem Area II, with one caveat: similar to METIS, PRIMES/IEM cannot model CMs. On one hand this implies an underestimation of the benefits of the energy only market (Option 1) related to the more efficient operation of the system. On the other hand the modelled baseline could not be used for the comparison with Options 2 and 3. The approach followed to resolve this issue is described in the next section.

In order to enrich the analysis, and provide more comparability with the analysis performed for Problem Area I, it was decided to run also Options 1(a) (level playing field) and Option 1(b) (strengthening short-term markets) of Problem Area I. For the better understanding of the reader, the construction of these options is presented in a similar manner as for the METIS scenarios, highlighting that Option 0 corresponds to the baseline and Option 1(c) to Option 1 of Problem Area II. Options 1(a) (level playing field) and 1(b) (strengthening short-term markets) do not correspond to any specific option of Problem Area II, but are presented for completeness. The identification and methodology for the quantification of current practices was supported by the same study used for the METIS modelling.

Table 5: Overview of MDI impact assessment Problem Area II scenarios as modelled by PRIMES/IEM (read in conjunction with Table 4)

Action	Field	MDI options			
		0	1(a)	1(b)	1
1	DR deployment	a	b	b	c
2	RES E priority dispatch	a	b	c	d
3	Day-ahead and intraday liquidity	a	b	c	c
4	Intraday coupling	a	b	c	c
5	Reserve dimensioning	a	b	c	c
6	Reserve procurement methodology	a	a	b	b
7	Use of NTC and bidding zones assumption	a	a	b	b
8	Price Caps	a	b	b	b

Source: PRIMES/IEM

Table 6: Overview of the sub-options for each measure modelled in METIS

Measure	Topic	Description of the options
1	DR deployment	Three levels of DR deployment (sub-options a, b and c, with increasing economic potential, based on COWI BAU and PO2 scenarios) were considered. Assumptions were similar to METIS. As load shifting and load reductions could be captured in PRIMES/IEM, DR was modelled also for the day-ahead (not only for balancing / reserves as in METIS).
2	RES E priority dispatch	Four sub-options were considered: a. Priority dispatch for must take CHP, RES E, biomass and small-scale RES E b. As in (a), but biomass bids at marginal costs. c. As in (b), with no priority dispatch of RES E except small scale. RES E bidding at marginal costs minus FIT (wherever applicable). d. As in (c) but with no priority of small-scale RES E thanks to aggregators. Note that removal of priority dispatch is assumed to imply balance responsibility and capability to participate in intraday and offer balancing services. Thus for sub-option (d) all resources participate in intraday, offer balancing services and have balancing responsibilities.
3	Day-ahead and intraday liquidity	Three options were considered: a. Low liquidity. DAM covers part of the load, with many bilateral contracts nominated. ID illiquid in certain countries, in which case TSO has significant RR. b. Improved liquidity. DAM covers the large majority of the load, no nominations. ID illiquid in certain countries, in which case TSO has significant RR.

Measure	Topic	Description of the options
		c. Liquid markets. DAM covers the whole load. Liquid and harmonised ID markets.
4	Intraday coupling	Three options were considered: a. Very limited participation of flows over interconnectors (as available capacity for intraday is restricted to the minimum – defined by country) b. Limited participation of flows over interconnectors c. Entire physical capacity of interconnectors allocated to IDM and flow-based allocation of capacities, after taking into account remaining capacity of interconnectors.
5	Reserve dimensioning	Reserve was sized exogenously (own calculations). Three options were considered: a. High reserve requirements (national) b. High reserve requirements (national) but slightly reduced than in Option 0 c. EU-wide reserve requirements (nonetheless taking into account areas systematically congested)
6	Reserve procurement methodology	The options were: a. Current practices b. Day-ahead procurement(which was modelled in PRIMES/IEM as a joint optimization of power and reserve day-ahead procurement)
7	Use of NTC and bidding zones assumption	Two options were considered: a. Restrictive ATC (NTC – bilateral contracts – TSO reserves) – defined by country. National Bidding Zones (NTC values are given on existing border basis) b. Entire physical capacity of interconnectors allocated to DAM and flow-based allocation of capacities
8	Price Caps	Two options: a. Reflecting current practices b. Equal to VoLL, being the same for all Member States.

Source: PRIMES/IEM

PRIMES/OM policy scenarios for the options of Problem Area II

As already discussed in the previous section, the technical difficulty to model simultaneously specific wholesale market measures (removal of low price caps, locational signals for investments) with the issues on the coordination of CMs led to a two-step approach:

- Initially PRIMES/IEM was used to model Option 0 and Option 1 of Problem Area II. This was sufficient to show the benefit of Option 1.
- Subsequently PRIMES/OM was used to model Options 1 to 3 of Problem Area II, but not Option 0, this time the focus being on CMs. Comparison was performed among these three Options.

Due to the limitations of PRIMES/OM, all the detailed measures and assumptions under Option 1 could not be captured. Concerning bidding behaviour, the same approach as in PRIMES/IEM was followed. Table 7 presents a short comparison of the main results related to power generation for 2030 for the three models (PRIMES, PRIMES/IEM and PRIMES/OM).

Table 7: Comparison of results for PRIMES EUCO27, PRIMES/IEM Option 1(b) and PRIMES/OM Option 1 for 2030.

	PRIMES EUCO27	PRIMES/IEM Option 1(b)	PRIMES/OM Option 1
Net Installed Power Capacity (in MW_e)	**1,131,045**	as in EUCO27	**1,094,290**
Nuclear energy	109,905		109,905
Hydro (pumping excluded)	133,335		133,335
Wind on-shore	246,064		246,064
Wind off-shore	37,949		37,949
Solar	233,813		233,813
Biomass-waste fired	53,073		53,073
Other renewables	2,079		2,066
Solids fired	99,396		80,844
Oil fired	15,304		15,930
Gas fired	200,127		181,312
Net generation by plant type (in GWh)	**3,396,680**	**3,339,769**	**3,378,950**
Nuclear energy	738,363	678,318	737,365
Hydro (pumping excluded)	375,138	364,089	375,020
Wind on-shore	564,407	552,893	564,539
Wind off-shore	127,334	126,953	127,388
Solar	303,625	266,644	299,070
Biomass-waste fired	238,108	231,813	200,828
Other renewables	9,732	9,732	9,268
Solids fired	448,640	368,460	469,182
Oil fired	14,572	28,816[36]	11,754
Gas fired	576,760	712,051	584,537

Source: PRIMES

Apart from the differences in the installed capacities for solids and gas plants, explained in more detail in Section 6.2.6.3, the main difference is the increased generation of gas plants in detriment of solids and nuclear in PRIMES/IEM, most likely due to the better capturing of the flexibility needs of the system.

With Option 1 described above, Options 2 and 3 assume on top the inclusion of CMs for specific countries. Both Options assume CMs only in the case of Member States foreseeing adequacy problems in their markets. Therefore certain Member States needed to be chosen indicatively for this role. For the scope of this assessment, four countries were assumed to be in the need of a CM: France, Ireland, Italy and UK. This assumption was not based on a resource adequacy analysis, but on the CMs examined under DG COMP's Sector Inquiry, focusing specifically on countries with market-wide CMs.

When a country was assumed to have a CM in place, it was assumed that generators no longer followed scarcity pricing bidding behaviour, but shifted to marginal cost bidding.

[36] As the reported technology categories of PRIMES do not entirely match PRIMES/IEM, for PRIMES/IEM the reported figure in the table for oil fired generation includes peak units, steam turbines (both oil and gas) as well as CHP with oil as main fuel.

Therefore in Options 2 and 3 a hybrid market was considered for EU28, with 24 Member States having an energy only market (with scarcity pricing behaviour), while 4 Member States having and energy market (with marginal pricing behaviour) supplemented with a capacity mechanism.

Finally the only difference between Options 2 and 3, is that in Option 3 the CM is assumed to include rules foreseeing explicit participation of cross-border capacities. Cross-border capacities were assumed to participate to a CM up to a certain upper bound. The main idea for this calculation of this upper bound was similar to the concept of unforced available capacity, which is used in CMs for the generation capacities. Note though that using this concept for calculating unforced available capacity (or de-rated capacity) of interconnectors during system stress times is more complex because the probability of non-delivery is not due only to technical factors but it is mainly due to congestion factors, which can considerably vary depending on power trade circumstances during system stress times. To do this calculation it was necessary to dispose simulation results of the operation of the multi-country system. Alternatively, the calculation could be based on statistical data on system operation in past years. In both cases, the simulation requires calculation of power flows over the interconnection system.

Data collection and data gaps

The modelling performed for the impact assessment had significant data requirements. For example METIS requires about twenty different types of data (such as installed capacities, variable costs, availabilities, load factors and such). Depending on the type of simulation, over 25 million individual data points can be required for each single test case, mostly coming from hourly data (such as hourly national demands). For the NTUA models an ever larger set of data was required (multiple times larger), as PRIMES covers the whole European energy sector and all existing or emerging technologies, from household appliances to industrial processes and means of transport. The respective data were collected from public and commercial databases, as well as DG ENER EMOS database.

Moreover, in order to assess the impact of various measures and regulations aimed at improving the market functioning, one needs to compare the market outcome in the distorted situation, i.e. under current practices, with the market outcome after the implementation of new legislative measures. These distortions should be based on the current situation and practices and form the baseline for the impact assessment.

For this purpose the Commission requested assistance in the form of a study providing the necessary inputs, i.e. facts and data for the modelling of the impacts of removal of current market distortions. Although a significant amount of data was collected, a large number of desired data sets was either unavailable or undisclosed. This unavailability of data sometimes applied only for specific Member States for certain series, creating difficulties in using the collected data for the rest of the Member States. In these cases proxies need to be defined that could fill in the data gaps[37].

Modelling limitations

Every model is a simplification of reality. Thus, a model itself is not able to capture all features and facets of the real world. While one may be tempted to include as many features and options as possible, one has to be careful in order to avoid over-complication of models. This can very quickly result in overfitting (i.e. modelling relationships and cause and effects that do in this way not apply to reality, but yielding a better fit), and transparency issues (i.e. understanding in the end not the model results, or drawing wrong conclusions). It is therefore essential to find the right balance between complexity and transparency, taking the strengths and weakness of each modelling approach into account.

For these reasons, considering the limitations of each modelling approach, a number of compromises were made. There was an effort these compromises to retain the complexity of the modelling at the lowest possible level, in order to allo interpretability of results. The aforementioned study on market distortions also contributed in identifying the best modelling approaches to capture all major distortions.

One should also expect that the different models used, although all of them focus on the power sector, can produce different results due to the varying methodological approaches followed. As long as these differences are well-founded on the underlying methodology and scope of each model, while being based on the same underlying assumptions and input data, they can be considered as complementary, as they give a better overview of the impacts of the various policy options and help producing a more robust assessment.

[37] "*Electricity Market Functioning: Current Distortions, and How to Model their Removal*", COWI (2016).

Tool Concerned	Main Modelling Limitations		
	Leading to a possible overestimation of benefits	**Leading to a possible underestimation of benefits**	**With an unclear effect**
METIS & PRIMES/IEM	The baseline assumes current practices for a number of market design related measures and policies, not considering their possible evolution and the expansion of existing initiatives. As the situation is very unclear how these will advance in the coming years, and since modelling requires a specific assumption for each of these measures, it was decided for these cases (e.g. DR participation in the markets) to reflect a more pessimistic view, where only few advancements are made. In this respect the costs of the baseline are quite likely overestimated.	The detrimental effects of capacity mechanisms or support schemes for RES E to the efficiency of the electricity market operation over the various time frames, as well as the external costs to the power system (in relation to the energy market), were not considered. Still these are touched in Problem Area II and the RED II impact assessment, as well as strong indication on the impacts of RES E subsidies can be deduced by the effect of the removal of priority dispatch for biomass plants. The softer approach used for the modelling of priority dispatch of variable RES E (wind, solar) underestimates the relevant cost of the baseline scenario. Similarly for the balancing responsibility, where H-2 forecasts for RES E are used, even when balance responsibility is not assumed to apply to them. METIS did not model CHP and small scale RES E separately, which would further enhance the impacts of priority dispatch, currently assessed only for biomass.	Modelling of the day-ahead and reserve procurement is based on the so-called co-optimization of energy and reserves. This approach was the one implemented for simplicity and transparency. At the same time though it does lead to the optimal scheduling of units. This on one hand underestimates the costs of the baseline (in the case of METIS), but at the same time possibly over-estimates the benefits of the policy options. Still overall the specific choice should not be considered pivotal. Well-designed markets should lead to the same efficient operation of the power system. Liquid intraday and balancing markets should optimize operation and resolve possible infeasibility issues resulting from the DA schedule.
METIS	The yearly dimensioning and procurement of reserves overestimates the cost of current practices, not even considering their possible evolution, based on which are very likely to be brought even closer to real time in the coming years. This is partially compensated by assuming that dimensioning is performed based on the more accurate probabilistic approach (despite currently performed in many Member States based on the deterministic one). Also by the fact that in all sub-options dimensioning of mFRR and FCR does not vary (thus no benefits are reported for this).	The issue of the limited liquidity currently observed in intraday and balancing markets is not captured in the modelling. Thus METIS assumed that markets would be liquid in 2030, which may very well be indeed the case without any policy action. Note though that in certain Member States these markets may not even exist today,	Continuous intraday trading was modelled as consecutive hourly implicit auctions.
METIS		Even in the baseline, interconnector capacity is	The assumed effect of the measures on the interconnector

Tool Concerned	Main Modelling Limitations		
	Leading to a possible overestimation of benefits	Leading to a possible underestimation of benefits	With an unclear effect
		assumed to be allocated and used relatively efficiently. Moreover the absence of network modelling implied that all relevant (and in many cases significant) costs were not considered, especially related to internal congestion (within Member States).	capacities (i.e. the increase of NTC capacities) for the various options was performed in a stylized manner. It was based on very rough estimations due to the significant lack of relevant data.
METIS		DR was modelled as if participating only in balancing markets and reserves, but not in day-ahead / intraday. Benefits from load shifting or load reductions were not assessed due to the lack of sufficient detailed data. A standard load profile was used for demand, based on ENTSO-E's TYNDP 2016 assumptions. A dynamic profile for demand and storage would better capture the reactions of demand to market prices (and the associated benefits).	Stylized modelling approach concerning costs of DR.
METIS		Competition issues, effects of nominations and block-bids, as well as possible strategic behaviour of the market participants were not considered. On the contrary, perfect competition was assumed based on marginal pricing.	
PRIMES/IEM & PRIMES/OM		Assumed bidding behaviour on behalf of market participants was not considered very aggressive, with the electricity price rarely reaching the price caps.	Modelling required a significant amount of inputs and exogenous assumptions, e.g. on market behaviour etc., with data not necessarily available (generally, not just publicly).Moreover significant amount of data (e.g. detailed data on RR, nominations, technical details on the transmission grid) were missing, so had to be estimated by the modellers. Thus results are quite dependant on these inputs. Still every effort was made to confirm assumptions based on currently observed market operation data.
PRIMES/OM		The fact that the baseline does not capture the possible overcapacity in the power markets, e.g. due to existing CMs or RES E support schemes or due to unrealised forecasts of the market participants, takes	The selection of the countries assumed to have a CM may be influencing the results (in an uncertain direction). Each combination of countries could possibly lead to different results.

Tool Concerned	Main Modelling Limitations		
	Leading to a possible overestimation of benefits	**Leading to a possible underestimation of benefits**	**With an unclear effect**
		away part of the benefits that would be realised from well-functioning markets (and CMs).	For this reason a sensitivity was performed assuming the existence of CMs for all countries, and then performing the comparison of Options 2 and 3 in this context.

Annex V: Evidence and external expertise used

The present impact assessment is based on a large body of material, all of which is referenced in the footnotes. A number of studies have however been conducted mainly or specifically for this impact assessment. These are listed and described further in the table below.

The Commission (DG Competition) has also been conducting a sector inquiry into national capacity mechanisms and organised Working Groups with Member States with a view to help them implement the provisions in the EEAG related to capacity mechanisms and to share experience in the design of capacity mechanisms[38].

[38] http://ec.europa.eu/competition/sectors/energy/state_aid_to_secure_electricity_supply_en.html

Study	Study serve to study/substantiate impact of	Contractor	Published
METIS Study 12: Assessing Market Design Options in 2030.	Assessing elements for upgrading the market (all options under Problem Area I) with a focus on the more efficient operation of the power system: - Removing Market Distortions - Allocating interconnection capacity across time frames - Procurement and Sizing of Balancing Reserves Impacts of the participation of Distributed Generation in the market	Modelling tool DG ENER/METIS Consortium	To be published[39]
METIS Study 04: Stakes of a common approach for generation and system adequacy.	Assessing the benefits from a coordinated approach in Generation and System Adequacy Analysis	Modelling tool DG ENER/METIS Consortium	To be published
METIS Study 16: Weather-driven revenue uncertainty for power producers and ways to mitigate it .	Effect of weather related uncertainty to revenues. Capacity savings due to cooperation. CM coordination/cross-border participation.	Modelling tool DG ENER/METIS Consortium	To be published
METIS Technical Note T04: Methodology for the integration of PRIMES scenarios into METIS.	Technical note providing details on the methodological approach followed with METIS.	METIS Consortium	To be published
METIS Technical Note T05: METIS market module	Technical note providing details on the	METIS Consortium / Thema	To be published

[39] Once operational, the envisaged link is expected to be the following: https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis. Same applies for all METIS studies.

Study	Study serve to study/substantiate impact of	Contractor	Published
configuration for Study S12 - Focus on day-ahead, intraday and balancing markets.	methodological approach followed with METIS.	Consulting	
"*Methodology and results of modelling the EU electricity market using the PRIMES/IEM and PRIMES/OM models*"	A. Assessing elements for upgrading the market (main options under Problem Area I) with a focus on the revenues for the market players, including: - Scarcity pricing - Bidding Zones B. Assessing investment incentives and the need for coordination of CMs: - Profitability of power generation investments Coordination of CMs	NTUA	To be published
Electricity Market Functioning: Current Distortions, and How to Model Their Removal	Impact removing market distortions: - Identifying market distortions Providing data input and support for the modelling	COWI / Thema / NTUA	To be published
Framework for cross-border participation in capacity mechanisms	CM cross-border arrangements	COWI/Thema/NTUA	To be published
Transmission tariffs and Congestion income policies	Options for locational signals/regulatory framework IC construction	Trinomics	To be published

Study	Study serve to study/substantiate impact of	Contractor	Published
Integration of electricity balancing markets and regional procurement of balancing reserves	Main study supporting Balancing Guidelines IA. For MDI: regional sizing and procurement balancing reserves[40]	COWI/Artelys	To be published
Impact Assessment support Study on downstream flexibility, demand response and smart metering	Costs and benefits of measures to remove market barriers to demand response and make dynamic price tariffs more accessible	COWI / ECOFYS / THEMA / VITO	To be published
Study on future European electricity system operation	Future model TSO collaboration	Ecorys, DNV-GL,ECN	https://ec.europa.eu/energy/sites/ener/files/documents/15-3071%20DNV%20GL%20report%20Options%20for%20future%20System%20Operation.pdf
System adequacy assessment	Methodology for system adequacy assessments	JRC	To be published
Identification of Appropriate Generation and System Adequacy Standards for the Internal Electricity Market	System adequacy standards practises and methods	Mercados, E-bridge, ref4e	https://ec.europa.eu/energy/sites/ener/files/documents/Generation%20adequacy%20Final%20Report_for%20publication.pdf
Impact assessment support study on: “Policies for DSOs, Distribution Tariffs and Data Handling”	Cost and benefits of different options concerning DSO roles, distribution network tariffs, data handling models	Copenhagen Economics, and VVA	To be published
Second Consumer Market Study on the functioning of retail electricity markets for consumers in the EU	Billing information; contract exit fees; price comparison tools; disclosure and guarantees of origin	Ipsos, London Economics, and Deloitte	To be published
National policies on security of electricity supply	Review of current national rules and practices relating to risk preparedness in the area of security of electricity supply	VVA Consulting & Spark	https://ec.europa.eu/energy/sites/ener/files/documents/DG%20ENER%20Risk%20preparedness%20final%20report%20May2016.pdf
Measures to protect vulnerable consumers in the energy sector: an assessment of disconnection safeguards, social tariffs and financial transfers	Removing market distortions by phasing-out regulated prices Appraisal of disconnection safeguards across the EU.	INSIGHT_E	To be published

40 Examines in more detail issues that are going to be examined also on METIS Study S12.

Study	Study serve to study/substantiate impact of	Contractor	Published
Energy poverty and vulnerable consumers in the energy sector across the EU: analysis of policies and measures	Review of measures to protect energy poor and vulnerable consumers	INSIGHT_E	https://ec.europa.eu/energy/sites/ener/files/documents/INSIGHT_E_Energy%20Poverty%20-%20Main%20Report_FINAL.pdf
Selecting indicators to measure energy poverty	Review, appraisal and computation of indicators to measure energy poverty	Trinomics, University College London, and 7Seven	https://ec.europa.eu/energy/sites/ener/files/documents/Selecting%20Indicators%20to%20Measure%20Energy%20Poverty.pdf
Fuel poverty in the European Union: a concept in need of definition?	Critical assessment of the pros and cons of an energy poverty definition at the EU level	Harriet Thomson, Carolyn Snell and Christine Liddell	http://extra.shu.ac.uk/ppp-online/wp-content/uploads/2016/04/fuel-poverty-european-union.pdf
The role of DSOs in a Smart Grid environment	Assessment of the future role of DSOs in specific activities	ECN & Ecorys	https://ec.europa.eu/energy/sites/ener/files/documents/20140423_dso_smartgrid.pdf
Study on the effective integration of Distributed Energy Resources for providing flexibility to the electricity system	Assessment of distributed energy resources and their effectiveness in providing flexibility to the energy system	PwC, Sweco, Ecofys, Tractebel	https://ec.europa.eu/energy/sites/ener/files/documents/5469759000%20Effective%20integration%20of%20DER%20Final%20ver%202_6%20April%202015.pdf
From Distribution Networks to Smart Distribution Systems: Rethinking the Regulation of European Electricity DSOs	Assessment of the DSO role in the context of four regulatory areas including remuneration, network tariff structure and DSO activities	THINK	http://www.eui.eu/projects/think/documents/thinktopic/topic12digital.pdf
Options on handling Smart Grids Data	Description of different data handling options for smart grids	EC Smart Grids Task Force	https://ec.europa.eu/energy/sites/ener/files/documents/xpert_group3_first_year_report.pdf
Regulatory Recommendations for the Deployment of Flexibility	Description of the flexibility context, commercial and regulatory arrangements, incentives for the development of flexibility, policy recommendations	EC Smart Grids Task Force	https://ec.europa.eu/energy/sites/ener/files/documents/EG3%20Final%20-%20January%202015.pdf
Identifying energy efficiency improvements and saving potential in energy networks and demand response	Analysis of different options for improving efficiency in energy networks according to Article 15 of the EED	Tractebel, Ecofys	https://ec.europa.eu/energy/sites/ener/files/documents/GRIDEE_4NT_364174_000_01_TOTALDOC%20-%2018-1-2016.pdf
Study on tariff design for distribution systems	Benchmarking of different distribution tariff structures and levels for electricity and gas across EU	AF Mercados, refE, Indra	https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF

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Annex VI: Evaluation

The evaluation is presented as a self-standing document.

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Annex VII: Overview of electricity network codes and guidelines

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Annex VII: Overview of electricity network codes and guidelines

This annex provides an overview of electricity network codes and guidelines adopted or envisaged under Articles 6, 8 and 18 of the Electricity Regulation as well as a brief description to the present initiative, if any.

Electricity network codes and guidelines adopted or envisaged under Articles 6, 8 and 18 of the Electricity Regulation	State of play	Brief description of contents I	Link to MD
Commission Regulation establishing a Guideline on capacity allocation and congestion management	Adopted on 24 July 2015	Legal implementation of day-ahead and intraday market coupling, flow-based capacity calculation	Linked to short-term markets For more details, see Annex 2.2
Commission Regulation establishing a Network code on requirements for grid connection of generators	Adopted on 14 April 2016	Defines the necessary technical capabilities of generators in order to contribute to system safety and to create a level playing field.	No direct link with MD
Commission Regulation establishing a Network Code on High Voltage Direct Current Connections and DC-connected Power Park Modules	Adopted on 26 August 2016	Technical connection rules for HVDC lines, e.g. used for connections of offshore wind farms	No direct link with MD
Commission Regulation establishing a Network code on demand connection	Adopted on 17 August 2016	Defines the necessary technical specifications of demand units connected to a grid and DSOs in order to contribute to system safety and to create a level playing field.	Link to demand response and to measures on ancillary services For more details, see Annex 3.1
Commission Regulation establishing a Guideline on Forward Capacity Allocation	Adopted on 26 September 2016	Creation of hedging opportunities for the electricity market; important to facilitate cross-border trade; capacity to be allocated through auctions on a central booking platform; harmonisation of capacity products	Link to short-term markets, scarcity pricing and locational signals. See Annexes 2.2, 4.1, 4.2
Commission Regulation establishing a Guideline on electricity transmission System Operation	Text voted favourably by MS on 4 May Target date for launching scrutiny: December 2016	Rules to react to system incidents (TSO interaction when the system goes beyond acceptable operational ranges) Creation of a framework for TSO cooperation in the preparation of system operation (i.e. planning ahead of real time). Guidance for how TSOs should create a framework for keeping system frequency within safe operational ranges	Linked to TSO cooperation in the planning and operation of transmission systems. For more details, see Annex 2.3
Draft Commission Regulation establishing a Guideline on Electricity Balancing **('Balancing Guideline')**	Target for vote in comitology: by end 2016	First step to the development of common merit order lists for the activation of balancing energy and the start of a harmonisation of balancing products.	Linked to procurement rules and sizing of balancing reserves. For more details, see Annex 2.1
Draft Commission Regulation establishing a Network code on Emergency and Restoration	Target for vote in comitology: first quarter 2017	Defines requirements of the plans to be adopted by TSOs concerning procedures to be followed when blackouts happen	Linked to security of supply measures. For more details, see Annex 6

Annex VIII: Summary tables of options for detailed measures assessed under each main option

The tables provided here reflect the in-depth assessment made of the options for detailed measures described in the Annexes to the impact assessment Chapter 1.1 through to 7.6

The manner in which they correspond to the main options assessed in the present document is set out in Table 6, Table 7, Table 8 and Table 9 in the present document

Measures assessed under Problem Area 1, Option 1(a): level playing field amongst participants and resources

Priority access and dispatch

Objective: To ensure that all technologies can compete on an equal footing, eliminating provisions which create market distortions unless clear necessity is demonstrated, thus ensuring that the most efficient option for meeting the policy objectives is found. Dispatch should be based on the most economically efficient solution which respects policy objectives.

	Option 0	Option 1	Option 2	Option 3
Description	Do nothing. This would maintain rules allowing priority dispatch and priority access for RES, indigenous fuels and CHP.	Abolish priority dispatch and priority access This option would generally require full merit order dispatch for all technologies, including RES E, indigenous fuels such as coal, and CHP. It would ensure optimum use of the available network in case of network congestion.	Priority dispatch and/or priority access only for emerging technologies and/or for very small plants: This option would entail maintaining priority dispatch and/or priority access only for small plants or emerging technologies. This could be limited to emerging RES E technologies, or also include emerging conventional technologies, such as CCS or very small CHP.	Abolish priority dispatch and introduce clear curtailment and re-dispatch rules to replace priority access. This option can be combined with Option 2, maintaining priority dispatch/access only for emerging technologies and/or for very small plants
Pros	Lowest political resistance	Efficient use of resources, clearly distinguishes market-based use of capacities and potentially subsidy-based installation of capacities, making subsidies transparent.	Certain emerging technologies require a minimum number of running hours to gather experiences. Certain small generators are currently not active on the wholesale market. In some cases, abolishing priority dispatch could thus bring significant challenges for implementation. Maintaining also priority access for these generators further facilitates their operation.	As Option 1, but also resolves other causes for lack of market transparency and discrimination potential. It also addresses concerns that abolishing priority dispatch and priority access could result in negative discrimination for renewable technologies.
Cons		Politically, it may be criticized that subsidized resources are not always used if there are lower operating cost alternatives. Adds uncertainty to the expected revenue stream, particularly for high variable cost generation.	Same as Option 1, but with less concerns about blocking potential for trying out technological developments and creating administrative effort for small installations. Especially as regards small installations, this could however result in significant loss of market efficiency if large shares of consumption were to be covered by small installations.	Legal clarity to ensure full compensation and non-discriminatory curtailment may be challenging to establish. Unless full compensation and non-discrimination is ensured, priority grid access may remain necessary also after the abolishment of priority dispatch.

Most suitable: Option 3. Abolishing priority dispatch and access exposes generators to market signals from which they have so far been shielded, and requires all generators to actively participate in the market. This requires clear and transparent rules for their market participation, in order to limit increases in capital costs and ensure a level playing field. This should be combined with Option 2: while aggregation can reduce administrative efforts related thereto, it is currently not yet sufficently developed to ensure also very small generators and/or emerging technologies could be active on a fully level playing field; they should thus be able to benefit from continuing exemptions.

Regulatory exemptions from balancing responsibility

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

RES E access to provision of non-frequency ancillary services

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

Measures assessed under Problem Area 1, Option 1(b) Strengthening short-term markets

Reserves sizing and procurement

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

Removing distortions for liquid short-term markets

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

Improving the coordination of Transmission System Operation

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

Measures assessed under Problem Area 1,Option 1(c); Pulling demand response and distributed resources into the market

Unlocking demand side response

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

Distribution networks

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

Remuneration of DSOs

Objective: A performance-based remuneration framework which incentivize DSOs to increase efficiencies in planning and innovative operation of their networks.		
Option: O	**Option 1**	**Option 2**
BAU Member States (NRAs) are mainly responsible on deciding on the detailed framework for remuneration of DSOs.	- Put in place key EU-wide principles and guidance regarding the remuneration of DSOs, including flexibility services in the cost-base and incentivising efficient operation and planning of grids. - Require DSO to prepare and implement multi-annual development plans, and coordinate with TSOs on such multi-annual development plans. - Require NRAs to periodically publish a set of common EU performance indicators that enable the comparison of DSOs performance and the fairness of distribution tariffs.	- Fully harmonize remuneration methodologies for all DSOs at EU level.
Pro Current framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro Performance based remuneration will incentivise DSOs to become more cost-efficient and offer better quality services. It would support integration of RES E and EU targets.	Pro A harmonized methodology would guarantee the implementation of specific principles.
Con Current EU framework provides only some general principles, and not specific guidance towards regulatory schemes which incentivize DSOs and raise efficiencies.	Con Detail implementation will still have to be realized at Member State level, which may reduce effectiveness of measures in some cases.	Con A complete harmonisation of DSO remuneration schemes would not meet the specificities of different distribution systems. Therefore, such an option would possibly have disproportionate effects while not meeting subsidiarity principle.
Most suitable option(s): Option 1 is the preferred option as it will reinforce the existing framework by providing guidance on effective remuneration schemes and enhancing transparency requirements		

Distribution network tariffs

Objective: Distribution tariffs that send accurate price signals to grid users and aim to fair allocation of distribution network costs.		
Option: 0	**Option 1**	**Option 2**
BAU Member States (NRAs) are mainly responsible on deciding on the detailed distribution tariffs.	- Impose on NRAs more detailed transparency and comparability requirements for distribution tariffs methodologies. - Put in place EU-wide principles and guidance which ensure fair, dynamic, time-dependent distribution tariffs in order to facilitate the integration of distributed energy resources and self-consumption.	- Harmonization of distribution tariffs across EU; fully harmonize distribution tariff structures at EU level for all EU DSOs, through concrete requirements for NRAs on tariff setting.
Pro Current framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro Principles regarding network tariffs will increase efficient use of the system and ensure a fairer allocation of network costs.	Pro A harmonized methodology would guarantee the implementation of specific principles.
Con Current EU framework provides only some general principles, and not specific guidance towards distribution network tariffs which effectively allocate costs and accommodate EU policies.	Con Detail implementation will still have to be realized at Member State level, which may reduce effectiveness of measures in some cases.	Con A complete harmonisation of DSO structures would not meet the specificities of different distribution systems. Therefore, such an option would possibly have disproportionate effects while not meeting subsidiarity principle.
Most suitable option(s): Option 1 is the preferred option as it will reinforce the existing framework by providing guidance on effective distribution network tariffs and enhancing transparency requirements		

Improving the institutional framework

Objective: To adapt the Institutional Framework, in particular ACER's decision-making powers and internal decision-making to the reality of integrated regional markets and the proposals of the Market Design Initiative, as well as to address the existing and anticipated regulatory gaps in the energy market.			
	Option 0	**Option 1**	**Option 2**
Description	Maintain status quo, taking into account that the implementation of network codes would bring certain small scale adjustments. However, the EU institutional framework would continue to be based on the complementarity of regulation at national and EU-level.	Adapting the institutional framework to the new realities of the electricity system and to the resulting need for additional regional cooperation as well as to addressing existing and anticipated regulatory gaps in the energy market.	Providing for more centralised institutional structures with additional powers and/or responsibilities for the involved entities.
Pros	Lowest political resistance.	Addresses the shortcomings identified and provides a pragmatic and flexible approach by combining bottom-up initiatives and top-down steering of the regulatory oversight.	Addresses the shortcomings identified with limited coordination requirements for institutional actors.
Cons	The implementation of the Third Package and network codes is not sufficient to overcome existing shortcomings of the institutional framework.	Requires strong coordination efforts between all involved institutional actors.	Significant changes to established institutional processes with the greatest financial impact and highest political resistance.
Most suitable: Option 1, as it adapts the institutional framework to the new realities of the electricity system by adopting a pragmatic approach in combining bottom-up initiatives and top-down steering of the regulatory oversight.			

Measures assessed under Problem Area 2, Option 2(1); Improved energy-only market without CMs)

Removing price caps

Objective: to ensure that prices in wholesale markets are not prevented from reflecting scarcity and the value that society places on energy.			
	Option 0: Business as usual	**Option 1: Eliminate all price caps**	**Option 2: Create obligation to set price caps, where they exist, at VoLL**
Description	Existing regulations already require harmonisation of maximum (and minimum) clearing prices in all price zones to a level which takes "into account an estimation of the value of lost load". Stronger enforcement/non-regulatory approach Enforceability of *"into account an estimation of the value of lost load"* in the CACM Guideline is not strong. Enforcement action is unlikely to be successful or expedient. Relying on stronger enforcement would leave considerable more legal uncertainty to market participants than clarifying the legal framework directly. Voluntary cooperation would not provide the market with sufficient confidence that governments would not step in restrict prices in the event of scarcity	Eliminate price caps altogether for balancing, intraday and day-ahead markets. Removes barriers for scarcity pricing Avoids setting of VoLL (for the purpose of removing negative effects of price caps).	Reinforced requirement to set price limits taking "into account an estimation of the value of lost load" Allow for technical price limits as part of market coupling, provided they do not prevent prices rising to VoLL. Establish requirements to minimise implicit price caps.
Pros	Simple to implement – leaves administration to technical implementation of the CACM Guideline.	Measure simple to implement; unequivocally and creates legal certainty.	Compatible with already existing requirement to set price limit, as provided for undert the CACM regulation, provides concrete legal clarity
Cons	Difficult to enforce; no clarity on how such clearing prices will be harmonised. Does not prevent price caps being implemented by other means.	Can be considered as non-proportional; could add significant risk to market participants and power exchanges if there are no limits.	VoLL, whilst a useful concept, is difficult to set in practice. A multitude of approaches exist and at least some degree of harmonisation will be required.
Most suitable: Option 2 - this provides a proportionate response to the issue –, it would allow for technical limits as part of market coupling and this should not restrict the markets ability to generate prices that reflect scarcity..			

Improving locational price signals

Objective: The objective is to have in place a robust process for deciding on the structure of locational price signals for investment and dispatch decisions in the EU electricity wholesale market.

	Option 0	**Option 1**	**Option 2**	**Option 3**
Description	Business as Usual – decision on bidding zone configuration left to the arrangements defined under the CACM Guideline or voluntary cooperation, which has, to date, retained the status quo .	Move to a nodal pricing system.	Introduce locational signals by new means, i.e. through transmission tariffs.	Improve currently existing the CACM Guideline procedure for reviewing bidding zones and introducing supranational decision-making, e.g. through ACER. This would be coupled with a strengthened requirement to avoid the reduction of cross-zonal capcity in order to resolve internal congestions.
Pros	Approach already agreed.	Theoretically, nodal pricing is the most optimal pricing system for electricity markets and networks.	Would unlock alternative means to provide locational signals for investment and dispatch decisions.	This improvement will render revisions of bidding zones a more technical decision. It will also increase the available cross-zonal capacity.
Cons	Risks maintenance of the status quo, and therefore misses the opportunity to address issues in the internal market.	Nodal pricing implies a complete, fundamental overhaul of current grid management and electricity trading arrangements with very substantial transition costs.	Incentives would be not be the result of market signals (value of electricity) but cost components set by regulatory intervention of a potentially highly political nature. Does not address the underlying difficulty of introducing locational price zones, namely the difficulties to arrive at decisions that reflect congestion instead of political borders.	Does not address a situation where the results of the bidding zone review are sub-optimal. I.e. this option only covers procedural issues.

Most suitable: Option 3 – this option will rely on a pre-established process but improve the decision-making so that decisions take into account cross-border impact of bidding zone configuration. Other options – e.g. tofundamentally change how locational signals are provided, would be dispropritionate.

Minimise investment and dispatch distortions due to transmission tariff structure

Objective: to minimise distortions on investment and dispatch patterns created by different transmission tariffs regimes.				
	Option 0: Business as usual	**Option 1: Restrict charges on producers (G-charges)**	**Option 2: Set clearer principles for transmission charges**	**Option 3: Harmonisation transmission tariffs**
Description	This option would see the status quo maintained, and transmission tariffs set according to the requirements under Directive 72 and the ITC regulation. Stronger enforcement and voluntary cooperation: There is no stronger enforcement action to be taken that would alone address the objective. Voluntary cooperation would, in part, be undertaken as part of implementation of Option 2.	This option could see the prohibition of transmission charges being levied on generators based on the amount of energy they generate (energy-based G-charges)	This option would see a requirement on ACER to develop more concrete principles on the setting of transmission tariffs, along with an elaboration of exiting provisions in the electricity regulation where appropriate.	Full harmonisation of transmission tariffs.
Pros	Pros: Minimal change; likely to receive some support for not taking any action in the short-term.	Eliminating energy-based G-charges would serve to limit distortionary effects on dispatch of generation caused by transmission tariffs. Social welfare benefits of approximately EUR 8 million per year. Would impact a minority of Member States (6-8 depending on design).	Provides an opportunity to move in the right direction whilst not risking taking the wrong decisions or introducing inefficiencies because of unknowns; consistent with a phased-approach; could eliminate any potential distortions without the need to mandate particular solutions; consistent with the introduction of legally binding provisions in the future, e.g. through implementing legislation.	Minimises distortion between Member States on both investment and dispatch; creates a level-playing field.
Cons	In the longer-term, likely to be a drive to do more and maintaining the status quo unlikely to be attractive; risks of continued divergence in national approaches.	Social welfare benefits relatively small – could be outweighed by transitional costs in the early years. Can be considered 'incomplete' as a number of other design elements of transmission tariffs contribute to distortionary effects.	Still leaves the door open for variation in national approaches; will not resolve all potential issues.	Unlikely to a proportionate response to the issues at this stage; given the technicalities involved, it could be more appropriate to introduce such measures as implementing legislation in the future.
Most suitable option(s): Option 2 – aside from some high-level requirements, given the complexity of transmission charges, the precise modalities should be set-out as part of implementing legislation in the future if and when appropriate. The value in Option 2 will be to set the path for the longer-term.				

Congestion income spending to increase cross-border capacity

Objective: The objective of any change should be to increase the amount of money spent on investments that maintain or increase available interconnection capacity				
	Option 0: Business as usual	**Option 1**	**Option 2**	**Option 3**
Description	This option would see the current situation maintained, i.e. that congestion income can be used for (a) guaranteeing the actual availability of allocated capacity or (b) maintaining or increasing interconnection capacities through network investments; and, where they cannot be efficiently used for these purposes, taken into account in the calculation of tariffs. Stronger enforcement: current rules do not allow for stronger enforcement. Voluntary cooperation: would offer no certainty that the allocation of income would change.	Further prescription on the use of congestion income, subjecting its use on anything other than (a) guaranteeing the actual availability of allocated capacity or (b) maintaining or increasing interconnection capacities (i.e. allowing it to be offset against tariffs) to harmonised rules.	Require that any income not used for (a) guaranteeing availability or (b) maintaining or increasing interconnection capacities flows into the Energy part of CEF-E or its successor, to be spent on relieving the biggest bottlenecks in the European electricity system, as evidenced by mature PCIs.	Transfer the responsibility of using the revenues resulting from congestion and not spent on either (a) guaranteeing availability or (b) maintaining capacities to the European Commission. De facto all revenues are allocated to CEF-E or successor funds to manage investments which increase interconnection capacity.
Pros	Minimal disruption to the market; consumers can benefit from tariff reductions – unclear whether benefits of better channelling income towards interconnection would provide more benefits to consumers, given that it may offset (at least in part) money spent on interconnection from other sources.	More guarantee that income will be spent on projects that increase or maintain interconnection capacity and relieve the most significant bottlenecks; could provide around 35% extra spend; approach reflects the EU-wider benefits of electricity exchange through interconnectors; can be linked to the PCI process.	Guarantees that income will be spent on projects that increase or maintain interconnection capacity and relieve the most important bottlenecks; could provide up to 35% extra spend; approach reflects the EU-wider benefits of electricity exchange through interconnectors; firm link with the PCI process.	Best guarantee that income will be spent on the biggest bottlenecks in the European electricity system, ensuring the best deal for European consumers in the longer run; approach reflects the EU-wider benefits of electricity exchange through interconnectors; to be linked to the PCI process.

Cons	Missing a potentially significant source of income which could be spent on interconnection and removing the biggest bottlenecks in the EU.	Restricts regulators in their tariff approval process and of TSOs on congestion income spending. Additional reporting arrangements will be necessary. Requires stronger role of ACER.	Restricts regulators in their tariff approval process and of TSOs on congestion income spending. Could mean that congestion income accumulated from one border is spent on a different border or different MS. Additional reporting arrangements will be necessary. Requires stronger role of ACER.	Could prove complicated to set up such an arrangement; could mean that congestion income accumulated from one border is spent on a different border or different MS. Requires a decision to apportion generated income to where needs are highest in European system. Will face national resistance. Will require additional reporting arrangements to be put in place. Requires stronger role of ACER.
Most suitable option(s): Option 2 – provides additional funding towards project which benefit the EU internal market as a whole, while still allowing for national decision making in the first instance. Considered the most proportionate response.				

Measures assessed under Problem Area 2, Option 2(2) CMs based on an EU-wide resource adequacy assessment

Improved resource adequacy methodology

Objective: Pan-European resource adequacy assessments				
	Option 0	**Option 1**	**Option 2**	**Option 3**
Description	Do nothing. National decision makers would continue to rely on purely national resource adequacy assessments which might inadequately take account of cross-border interdependencies. Due to different national methodologies, national assessments are difficult to compare.	Binding EU rules requiring TSOs to harmonise their methodologies for calculating resource adequacy + requiring MS to exclusively rely on them when arguing for CMs.	Binding EU rules requiring ENTSO-E to provide for a single methodology for calculating resource adequacy + requiring MS to exclusively rely on them when arguing for CMs.	Binding EU rules requiring ENTSO-E to carry out a single resource adequacy assessment for the EU + requiring MS to exclusively rely on it when arguing for CMs.
Pros	Stronger enforcement: Commission would continue to face difficulties to validate the assumptions underlying national methodologies including ensuing claims for Capacity Mechanisms (CMs).	National resource adequacy assessments would become more comparable.	In addition to benefits in Option 1, it would make it easier to embark on the single methodology.	In addition to benefits in Options 1 & 2, it would make sure that the national puzzles neatly add up to a European picture allowing for national/ regional/ European assessments. Results are more consistent and comparable as one entity (ENTSO-E) is running the same model for each country.
Cons		Even in the presence of harmonised methodologies national assessment would not be able to provide a regional or EU picture.	Even in the presence of a single methodology, national assessments would not be able to provide a regional or EU picture. National TSOs might be overcautious and not take appropriately cross-border interdependencies into account. Difficult to coordinate the work as the EU has 30+ TSOs.	It would potentially reduce the 'buy-in' from national TSOs who might still be needed for validating the results of ENTSO-E's work.
Most suitable option(s): Option 3 - this approach assesses best the capacity needs for resource adequacy and hence allows the Commission to effectively judge whether the proposed introduction of resource adequacy measures in single Member States is justified.				

Cross-border operation of capacity mechanisms

Objective: Framework for cross-border participation in capacity mechanisms			
	Option 0	**Option 1**	**Option 2**
Description	Do nothing. No European framework laying out the details of an effective cross-border participation in capacity mechanisms. Member States are likely to continue taking separate approaches to cross-border participation, including setting up individual arrangements with neighbouring markets.	Harmonised EU framework setting out procedures including roles and responsibilities for the involved parties (e.g. resource providers, regulators, TSOs) with a view to creating an effective cross-border participation scheme.	Option 1 + EU framework harmonising the main features of the capacity mechanisms per category of mechanism (e.g. for market-wide capacity mechanisms, reserves, …).
Pros	Stronger enforcement The Commission's Guidance on state interventions[41] and the EEAG require among others that such mechanisms are open and allow for the participation of resources from across the borders. There is no reason to believe that the EEAG framework is not enforced. To date, however, there are not many practical examples of such cross-border schemes.	It would reduce complexity and the administrative impact for market participants operating in more than one MS/bidding zone. It would remove the need for each MS to design a separate individual solution – and potentially reduce the need for bilateral negotiations between TSOs and regulators. It would preserve the properties of market coupling and ensure that the distortions of uncoordinated national mechanisms are corrected and internal market able to deliver the benefits to consumers.	In addition to benefits in Option 1, it would facilitate the effective participation of foreign capacity as it would simplify the design challenge and would probably increase overall efficiency by simplifying the range of rules market participants, regulators and system operators have to understand.
Cons	As the conclusion of individual cross-border arrangements depend on the involved parties' willingness to cooperate it is likely that this option will cement the current fragmentation of capacity mechanisms. Arranging cross-border participation on individual basis is likely to involve high transaction costs for all stakeholders (TSOs, regulators, ressource providers).	It would be a cost for TSOs and regulators which would have to agree on the rules and enforce them across the borders. These costs would be lower than in Option 0 though.	In addition to the drawback of Option 1, it would limit the choice of instruments.
Most suitable Option(s): Options 1 and 2			

41 http://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd01_en.pdf

Options for measures assessed under Problem Area 3: a new legal framework for preventing and managing crises situations

Objective: Ensure a common and coordinated approach to electricity crisis prevention and management across Member States, whilst avoiding undue government intervention

	Option 0: Do nothing	**Option 0+: Non-regulatory approach**	**Option 1: Common minimum EU rules for prevention and crisis management**	**Option 2: Common minimum EU rules plus regional cooperation, building on Option 1**	**Option 3: Full harmonisation and full decision-making at regional level, building on Option 2**
		This option was disregarded as no means for enhanced implementation of the existing acquis nor for enhanced voluntary cooperation were identified			
Assessments	Rare/extreme risks and short-term risks related to security of supply are assessed from a national perspective. Risk identification & assessment methods differ across Member States.		Member States to identify and assess rare/extreme risks based on common risk types.	ENTSO-E to identify cross-border electricity crisis scenarios caused by rare/extreme risks, in a regional context. Resulting crisis scenarios to be discussed in the Electricity Coordination Group. Common methodology to be followed for short-term risk assessments (ENTSO-E Seasonal Outlooks and week-ahead assessments of the RSCs).	All rare/extreme risks undermining security of supply assessed at the EU level, which would be prevailing over national assessment.

Plans	Member States take measures to prevent and prepare for electricity crisis situations focusing on national approach, and without sufficiently taking into account cross-border impacts. No common approach to risk prevention & preparation (e.g., no common rules on how to tackle cybersecurity risks).		Member States to develop mandatory national Risk Preparedness Plans setting out who does what to prevent and manage electricity crisis situations. Plans to be submitted to the Commission and other Member States for consultation. Plans need to respect common minimum requirements. As regards cybersecurity, specific guidance would be developed.	Mandatory Risk Preparedness Plans including a national and a regional part. The regional part should address cross-border issues (such as joint crisis simulations, and joint arrangements for how to deal with situations of simultaneous crisis) and needs to be agreed by Member States within a region. Plans to be consulted with other Member States in each region and submitted for prior consultation and recommendations by the Electricity Coordination Group. Member States to designate a 'competent authority' as responsible body for coordination and cross-border cooperation in crisis situations. Development of a network code/guideline addressing specific rules to be followed for the cybersecurity. Extension of planning & cooperation obligations to Energy Community partners.	Mandatory Regional Risk Preparedness Plans, subject to binding opinions from the European Commission. Detailed templates for the plans to be followed. A dedicated body would be created to deal with cybersecurity in the energy sector.

Crisis management	Each Member State takes measures in reaction to crisis situations based on its own national rules and technical TSO rules. No co-ordination of actions and measures beyond the technical (system operation) level. In particular, there are no rules on how to coordinate actions in simultaneous crisis situations between adjacent markets. No systematic information-sharing (beyond the technical level).		Minimum common rules on crisis prevention and management (including the management of simultaneous electricity crisis) requiring Member States to: (i) not to unduly interference with markets; (ii) to offer assistance to others where needed, subject to financial compensation, and to; (iii) inform neighbouring Member States and the Commission, as of the moment that there are serious indications of an upcoming crisis and during a crisis.	Minimum obligation as set out in Option 1. Cooperation and assistance in crisis between Member States, in particular simultaneous crisis situations, should be agreed ex-ante; also agreements needed regarding financial compensation. This also includes agreements on where to shed load, when and to whom. Details of the cooperation and assistance arrangements and resulting compensation should be described in the Risk Preparedness Plans.	Crisis is managed according to the regional plans, including regional load-shedding plans, rules on customer categorisation, a harmonized definition of 'protected customers' and a detailed 'emergency rulebook' set forth at the EU level.
Monitoring	Monitoring of security of supply predominatly at the national level. ECG as a voluntary information exchange platform.		Systematic discussion of ENTSO-E Seasonal Outlooks in ECG and follow up of their results by Member States concerned.	Systematic monitoring of security of supply in Europe, on the basis of a fixed set of indicators and regular outlooks and reports produced by ENTSO-E, via the Electricity Coordination Group. Systematic reporting on electricity crisis events and development of best practices via the Electricity Coordination Group.	A European Standard (e.g. for EENS and LOLE) on Security of Supply could be developed to allow performance monitoring of Member States.

Pros			Minimum requirements for plans would ensure a minimum level of preparedness across EU taking into account cyber security. EU wide minimum common principles would ensure predictability in the triggers and actions taken by Member States.	Common methodology for assessments would allow comparability and ensure compatibility of SoS measures across Member States. Role of ENTSO-E and RSCs in assessment can take into account cross-border risks. Risk Preparedness Plans consisting of a national and regional part would ensure sufficient coordination while respecting national differences and competences. Minimum level of harmonization for cybersecurity throughout the EU. Designation of competent authority would lead to clear responsibilities and coordination in crsis. Common principles for crisis management and agreements regarding assistance and remuneration in simultaneous scarcity situations would provide a base for mutual trust and cooperation and prevent unjustified intervention into market operation. Enhanced role of ECG would provide adequate platform for discussion and exchange between Member States and regions.	Regional plans would ensure full coherence of actions taken in a crisis.
Cons	Lack of cooperation in risk preparedness and managing crisis may distort internal market and put at risk the security of supply of neighbouring countries.		Risk assessment and preparedness plans on national level do not take into account cross-border risks and crisis which make the plans less efficient and effective. Minimum principles of crisis management might not sufficiently adress simultaneous scarcity situations.	The coordination in the regional context requires administrative resources. Cybersecurity here only covers electricity, whereas the provisions should cover all energy sub-sectors including oil, gas and nuclear.	Regional risk preparedness plans and a detailed templates would have difficulties to fit in all national specificities. Detailed emergency rulebook might create overlaps with existing Network Codes and Guidelines.
	Most suitable: Option 2, as it provides for sufficient regional coordination in preparation and managing crisis while respecting national differences and competences.				

Measures assessed under Problem Area 4: The slow deployment of new services, low levels of service and poor retail market performance

Addressing energy poverty

Objective: Better understanding of energy poverty and disconnection protection to all consumers				
	Option: 0	**Option: 0+**	**Option 1**	**Option 2**
	BAU: sharing of good practices.	BAU: sharing of good practices and increasing the efforts to correctly implement the legislation. Voluntary collaboration across Member States to agree on scope and measurement of energy poverty.	Setting an EU framework to monitor energy poverty.	Setting a uniform EU framework to monitor energy poverty, preventative measures to avoid disconnections and disconnection winter moratorium for vulnerable consumers.
Energy poverty		EU Observatory of Energy poverty (funded until 2030).	Option 0+: EU Observatory of Energy Poverty (funded until 2030). Generic description of the term energy poverty in the legislation. Transparency in relation to the meaning of energy poverty and the number of households in a situation of energy poverty Member States to measure energy poverty. Better implementation of the current provisions.	Option 0+: EU Observatory of Energy Poverty (funded until 2030). Specific definition of energy poverty based on a share of income spent on energy. Member States to measure energy poverty using required energy. Better implementation and transparency as in Option 1.
Disconnection safeguards		NRAs to monitor and report figures on disconnections.	NRAs to monitor and report figures on disconnections.	NRAs to monitor and report figures of disconnections. A minimum notification period before a disconnection. All customers to receive information on the sources of support and be offered the possibility to delay payments or restructure their debts, prior to disconnection. Winter moratorium of disconnections for vulnerable consumers.
Pros	Continuous knowledge exchange.	Stronger enforcement of current legislation and continuous knowledge exchange.	Clarity on the concept and measuring of energy poverty across the EU.	Standardised energy poverty concept and metric which enables monitoring of energy poverty at EU level. Equip MS with the tools to reduce disconnections.
Cons	Existing shortcomings of the legislation are not addressed: lack of clarity of the concept of energy poverty and the number of energy	Insufficient to address the shortcomings of the current legislation with regard to energy poverty and targeted	New legislative proposal necessary. Administrative costs.	New legislative proposal necessary. Higher administrative costs. Potential conflict with principle of subsidiarity. Specific definition of energy poverty may not be

	poor households persist. Energy poverty remains a vague concept leaving space for MS to continue inefficient practices such as regulated prices. Indirect measure that could be viewed as positive but insufficient by key stakeholders.	protection.		suitable for all MS. Safeguards against disconnection may result in higher costs for companies which may be passed to consumers. Safeguards against disconnection may also result in market distortions where new suppliers avoid entering markets where risks of disconnections are significant and the suppliers active in such markets raise margins for all consumers in order to recoup losses from unpaid bills. Moratorium of disconnection may conflict with freedom of contract.
Most suitable option: Option 1 is recommended as the most balanced package of measures in terms of the cost of measures and the associated benefits. Option 1 will result in a clear framework that will allow the EU and Member States to measure and monitor the level of energy poverty across the EU. The impact assessment found that the propose disconnection safeguards in Option 2 come at a cost. There is potential to develop these measures at the EU level. However, Member States may be better suited to design these schemes to ensure that synergies between national social services and disconnection safeguards can be achieved. Please note that Option 1 and Option 2 also include the measures described in Option 0+.				

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Phasing out regulated prices

Objective: Removing market distortions by achieving the phase-out of supply price regulation for all customers.			
Option: 0	**Option 1**	**Option 2a**	**Option 2b**
Making use of existing *acquis* to continue bilateral consultations and enforcement actions to restrict price regulation to proportionate situations justified by general economic interest, accompanied by EU guidance on the interpretation of the current acquis.	Requiring MS to progressively phase out price regulation for households by a deadline specified in new EU legislation, starting with prices below costs, while allowing transitional, targeted price regulation for vulnerable customers (e. g. in the form of social tariffs).	Requiring MS to progressively phase out price regulation, starting with prices below costs, for households above a certain consumption threshold to be defined in new EU legislation or by MS.	Requiring MS to progressively phase out below cost price regulation for households by a deadline specified in new EU legislation.
Pros: - Allows a case-by-case assessment of the proportionality of price regulation, taking into account social and economic particularities in MS	Pros: - Removes the distortive effect of price regulation after the target date. - Ensures regulatory predictability and transparency for supply activities across the EU.	Pros: - Limits the distortive effect of price regulation. - Would reduce the scope of price regulation therefore limiting its distortive impact on the market.	Pros: - Limits the distortive effect of price regulation and tackles tariff deficits where existent.
Cons: - Leads to different national regimes following case-by-case assessments. This would maintain a fragmented regulatory framework across the EU which translates into administrative costs for entering new markets.	Cons: - Difficult to take into account social and economic particularities in MS in setting up a common deadline for price deregulation.	Cons: - Difficult to take into account social and economic particularities in MS in defining a common consumption threshold above which prices should be deregulated.	Cons: - Defining cost coverage at EU level is economically and legally challenging. - Implementation implies considerable regulatory and administrative impact. - Price regulation even if above cost risks holding back investments in product innovation and service quality.
Most suitable option(s): Option 1 - Setting an end date for all price intervention would ensure the complete removal of market distortions related to end-user price regulation and help create a level playing field for supply activities across the EU while allowing targeted protection for vulnerable customers and/or energy poor.			

Level playing field for access to data

Objective: Creating a level playing field for access to data.		
Option: 0	**Option 1**	**Option 2**
BAU Member States are primarily responsible on deciding roles and responsibilities in data handling.	- Define responsibilities in data handling based on appropriate definitions in the EU legislation. - Define criteria and set principles in order to ensure the impartiality and non-discriminatory behaviour of entities involved in data handling, as well as timely and transparent access to data. - Ensure that Member States implement a standardised data format at national level.	- Impose a specific EU data management model (e.g. an independent central data hub) - Define specific procedures and roles for the operation of such model.
Pro Existing framework gives more flexibility to Member States and NRAs to accommodate local conditions in their national measures.	Pro The above measures can be applied independently of the data management model that each Member State has chosen. The measures will increase transparency, guarantee non-discriminatory access and improve competition, while ensuring data protection.	Pro Possible simplification of models across EU and easier enforcement of standardized rules.
Con The current EU framework is too general when it comes to responsibilities and principles. It is not fit for developments which result from the deployment of smart metering systems.	Con	Con High adaptation costs for Member States who have already decided and implementing specific data management models. Such a measure would disproportionally affect those Member States that have chosen a different model without necessarily improving performance. A specific model would not necessarily fit to all Member States, where solutions which take into account local conditions may prove to be more cost-efficient and effective.
Most suitable option(s): Option 1 is the preferred option as it will improve current framework and set principles for transparent and non-discriminatory data access from eligible market parties. This option is expected to have a high net benefit for service providers and consumers and increase competition in the retail market.		

Facilitating supplier switching

Objective: Facilitating supplier switching by limiting the scope of switching and exit fees, and making them more visible and easier to understand in the event that they are used.			
Option 0	**Option 0+**	**Option 1**	**Option 2**
BAU/Stronger enforcement	Stronger enforcement, following the clarification of certain concrete requirements in the current legislation through an interpretative note.	Legislation to define and outlaw all fees to EU household consumers associated with switching suppliers, apart from: 1) exit fees for fixed-term supply contracts; 2) fees associated with energy efficiency or other bundled energy services or investments. For both exceptions, exit fees must be cost-reflective.	Legislation to define and outlaw all fees to EU household consumers associated with switching suppliers.
Pros: - Evidence may suggest a degree of non-enforcement of existing legislation by national authorities. - No new legislative intervention necessary.	Pros: - Non-enforcement may be due to complex existing legislation. - No new legislative intervention necessary.	Pros: - Considerably reduces the prevalence of fees associated with switching suppliers, and hence financial/psychological barriers to switching.	Pros: - Completely eliminates one financial/psychological barrier to switching. - Simple measure removes doubt amongst consumers. - The clearest, most enforceable requirement without exceptions.
Cons: - Continued ambiguity in existing legislation may impede enforcement. - The vast majority of switching-related fees faced by consumers are permitted under current EU legislation.	Cons: - The vast majority of switching-related fees faced by consumers are permitted under current EU legislation. - Certain MS might ignore the interpretative note.	Cons: - Marginally reduces the range of contracts available to consumers, thereby limiting innovation. - An element of interpretation remains around exceptions to the ban on fees associated with switching suppliers.	Cons: - Would further restrict innovation and consumer choice, notably regarding financing options for beneficial investments in energy equipment as part of innovative supply products e.g. self-generation, energy efficiency, etc. - Impedes the EU's decarbonisation objectives, albeit marginally.
Most suitable option(s): Option 1 is the preferred option, as it represents the most favourable balance between probable benefits and costs.			

Comparison tools

Objective: Facilitating supplier switching by improving consumer access to reliable comparison tools.		
Option 0+	**Option 1**	**Option 2**
Cross-sectorial Commission guidance addressing the applicability of the Unfair Commercial Practices Directive to comparison tools	Legislation to ensure every Member State has at least one 'certified' comparison tool that complies with pre-specified criteria on reliability and impartiality	Legislation to ensure every Member State appoints an independent body to provide a comparison tool that serves the consumer interest
Pros: - Facilitates coherent enforcement of existing legislation. - Light intervention and administrative impact. - Cross-sectorial consumer legislation already requires comparison tools to be transparent towards consumers in their functioning so as not to mislead consumers (e.g. ensure that advertising and sponsored results are properly identifiable etc.). - Cross-sectorial approach addresses shortcomings in commercial comparison tools of all varieties. - Cross-sectorial approach minimizes proliferation of sector-specific legislation.	Pros: - Fills gaps in existing legislation vis-à-vis energy comparison tools. - Limited intervention in the market, in most cases. - Allows certifying all existing energy comparison tools regardless of ownership. - Proactively increases levels of consumer trust. - Ensures EU wide access. - The certified comparison websites can become market benchmarks, foster best practices among competitors	Pros: - NRAs able to censure suppliers by removing their offers from the comparison tool. - No obligation on private sector. - Reduces risks of favouritism in certification process. - Proactively increases levels of consumer trust.
Cons: - Does not apply to non-profit comparison tools. - Does not proactively increase levels of consumer trust. - The existing legislation does not oblige comparison tools to be fully impartial, comprehensive, effective or useful to the consumer.	Cons: - Existing legislation already requires commercial comparison tools to abide by certain of the criteria addressed by certification. - Requires resources for verification and/or certification. - Significant public intervention necessary if no comparison tools in a given MS meet standards.	Cons: - To be effective, Member States must provide sufficient resources for the development of such tools to match the quality of offerings from the private sector. - Well-performing for-profit tools could be side-lined by less effective ones run by national authorities.
Most suitable option(s): Option 1 is the preferred option because it strikes the best balance between consumer welfare and administrative impact. It also gives Member States control over whether they feel a certification scheme or a publicly-run comparison tool best ensures consumer engagement in their markets.		

Improving billing information

Objective: Ensuring that all consumer bills prominently display a minimum set of information that is essential to actively participating in the market.			
Option: 0	**Option 0+**	**Option 1**	**Option 2**
BAU/Stronger enforcement	Commission recommendation on billing information	More detailed legal requirements on the key information to be included in bills	A fully standardized 'comparability box' in bills
Pros: - 77% of energy consumers agree or strongly agree that bills are "easy and clear to understand". - Allows 'natural experiments' and other innovation on the design of billing information to be developed by MS. - Recent (2014) transposition of the EED means premature to address information on energy consumption and costs.	Pros: - Low administrative impact - Gives MS significant flexibility to adapt their requirements to national conditions. - Allows best practices to further develop.	Pros: - Ensures that the minimum baseline of existing practices is clarified and raised. - Allows best practices to further develop, albeit less than Option 0. - Improves comparability and portability of information. - Ensures consumers can easily find the information elements needed to facilitate switching. - Bill design left free to innovation.	Pros: - Highest legal clarity and comparability of offers and bills. - A level playing field for all consumers and suppliers across the EU. - Very little leeway for suppliers to differently interpret the legislation with regards to the presentation of information. - Ensures consumers can easily find the information elements needed to facilitate switching.
Cons: - Poor consumer awareness of market-relevant information can be expected to continue. - Does not respond to stakeholder feedback on need to ensure minimum standards.	Cons: - A recommendation is unenforceable and may be ignored by MS/utilities. - Poor consumer awareness of market-relevant information can be expected to continue. - Does not respond to stakeholder feedback on need to ensure minimum standards.	Cons: - Limits innovation around certain bill elements. - Remaining leeway in interpreting legal articles may lead to implementation and enforcement difficulties.	Cons: - Challenging to devise standard presentation which can accommodate differences between national markets. - Highest administrative impact. - Prescriptive approach prevents beneficial innovation. - Difficult to adapt bills to evolving technologies and consumer preferences.
Most suitable option(s): Option 1 is the preferred option as it likely to leads to significant economic benefits and increased consumer surplus without significant administrative costs or the risk of overly-prescriptive legislation at the EU level.			

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