Market4RES

D6.1.1 Report on the Roadmap for RES penetration under the current Target Model high-level principles (2014-2020)

Part 1: recommendations about RES support schemes and demand flexibility

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ABBREVIATIONS

BRP	Balance Responsible Party
BSP	Balancing Service Provider
CAPEX	Capital Expenditures
CBA	Cost-Benefit Analysis
CCS	Carbon capture and storage
CEER	Council of European Energy Regulators
DSM	Demand Side Management
DSO	Distribution System Operator
DSR	Demand Side Response
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
ESCO	Energy Service Company
ETS	Emissions Trading System
EU	European Union
FIP	Feed-in premium *(synonym: Price Premium)*
FIT	Feed-in tariff
IEA	International Energy Agency
IT	Information Technology
LCOE	Levelized Cost of Electricity
OPEX	Operating Expenditures
PP	Price Premium *(synonym: Feed-in Premium)*
PV	Photovoltaic
RES	Renewable Energy Sources
RES-E	Renewable Energy Sources for Electricity
SEDC	Smart Energy Demand Coalition
SO&AF	Scenario Outlook and Adequacy Forecast
TGC	Tradable Green Certificates
TM	Target Model
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
WACC	Weighted Average Cost of Capital
WP	Work Package

GLOSSARY

General terms

EU Target Model (TM)

The EU Target Model consist in a market design for the management of cross-border power exchanges at each timeframe (i.e. forward, day-ahead, intraday and balancing) and a coordinated approach to capacity calculation (see for example [1] for more details).

Demand response, demand flexibility, demand-side management

Those three terms all refer to the same principle, consisting in empowering consumers (residential, commercial or industrial) by providing control signals and/or financial incentives to make them adjust their electricity consumption at strategic times.

Market4RES project

Workstream 1	**"Short-term action objectives (2016 → 2020)":** Assuming the current generation fleet as an input and current implementation status of the target model, the focus is on determining appropriate, yet novel, instruments (and their subsequent accompanying national energy policies) for increased renewable electricity generation in support of the 20/20/20 targets;
Workstream 2	**"Long-term action objectives (post 2020 → 2030)":** Assuming the future generation fleet (beyond 2020) as a result of current market designs, and taking into account possible future changes in market design beyond the existing TM, the focus is on developing necessary additions or complementary instruments to the current design, which will induce investment incentives and phase out support schemes in the long term without compromising system adequacy or security of supply.
Work package 2	Opportunities, challenges and risks for RES-E deployment in a fully integrated European electricity market
Work package 3	Novel market designs & KPIs
Work package 4	Appropriate new market instruments for RES-E to meet the 20/20/20 targets
Work package 5	Modelling of electricity market design & Quantitative evaluation of policies for post 2020 RES-E targets
Work package 6	Conclusions & Recommendations & Procedure Guidelines

EXECUTIVE SUMMARY

Introduction

The Work Package 6 (WP6) is the concluding part of the Market4RES project. In this WP, the results from previous work packages are analysed and gathered into a set of conclusions and recommendations. Its major objective is therefore to recommend the steps towards a practical implementation of policy, legislation and regulations for the renewable electricity generation in order to secure a robust evolution of the EU Target Model (TM) beyond 2020.

The present report D6.1.1 (as well as its follow-up D6.1.2) is focused on the first work stream of the Market4RES project, which addresses the 2020 horizon, both in terms of generation fleet and in terms of possible market designs[1]. Its purpose is to deliver recommendations and roadmaps about two specific aspects of the current market design:

- **Short-term effects of RES support schemes:** Given the obligation to move towards market-based schemes, what will be the impacts of this change on short-term markets? Which proportion of wind and solar capacities should be concerned by these new schemes? How the market-based schemes shall be configured?
- **Participation of demand in short-term markets:** Demand response is seen as a solution to many problems, but has not been deployed yet on a large scale.[2] What will be the real impacts of such deployment? Which measures could be put in place to ensure that the benefits exceed the costs?

RES support schemes

Background

Energy markets alone could not deliver the desired level of renewables in the EU, meaning that some support has been needed to stimulate investment in renewable energy. At least two types of measures have been necessary: priority dispatch and financial support.

- **Priority dispatch** is the obligation on transmission system operators (TSOs) to schedule and dispatch energy from renewable generators ahead of other generators as far as secure operation of the electricity system permits. Overall, priority dispatch has been an important tool to facilitate the integration of RES-E into the power system.
- In Europe, in most cases the **financial support** to renewable generation has initially been granted in form of feed-in-tariffs (FiT), which guarantees a fixed price per unit of electricity generated (MWh) fed into the grid over a specific time period. This support has allowed

[1] Upcoming reports D6.2 and D6.3 will address the second work stream of the project, with focus on longer-term horizons (2030 and beyond) and on long-term energy markets and capacity markets.
[2] Consumers are typically exposed to general changes in price levels over some time, which they respond to. However, for e.g. within-day or real-time adaption of demand based on market prices, there are currently no large scale examples.

triggering the development of RES-E generation capacities – mainly from wind and solar sources – and has led to significant generation capacities in Europe.

Ultimately, the objective of the RES-E industry is to be competitive in a liberalised electricity market, and to deliver the benefits of this emission-free energy to consumers. Regulatory incentives for more mature RES-E power generation technologies would not be needed with a fully functioning electricity market and full internalisation of external costs. This necessary transition is discussed further within the next sections of this chapter.

The expected move from feed-in-tariffs to market-based schemes

Within this context, the Market4RES project has studied and qualitatively assessed several market design options for RES support. The results of the qualitative assessment are in line with the European Commission's new Environmental and Energy State Aid guidelines which require RES support:

- From 1 January 2016, to be granted as a premium in addition to the market price, whereby the generators sell its electricity directly in the market,
- From 1 January 2017, to be granted in a competitive bidding process on the basis of clear, transparent and non-discriminatory criteria (with some exemptions, notably for small installations).

The Guidelines also foresee that RES producers are subject to standard balancing responsibilities, unless no liquid intra-day markets exist, and that measures are put in place to ensure that generators have no incentive to generate electricity under negative prices.

This new legal framework will lead to profound changes in the support to renewable energy sources. Such changes are likely to have significant impacts on RES generation and possibly on the whole power system. The Market4RES project has therefore conducted a quantitative analysis on the impact on short-term market outcomes of such move from feed-in-tariffs to market-based schemes. The impacts of RES support schemes have been assessed in terms of volumes exchanged on the day-ahead market, costs and profits, market prices, and sustainability.

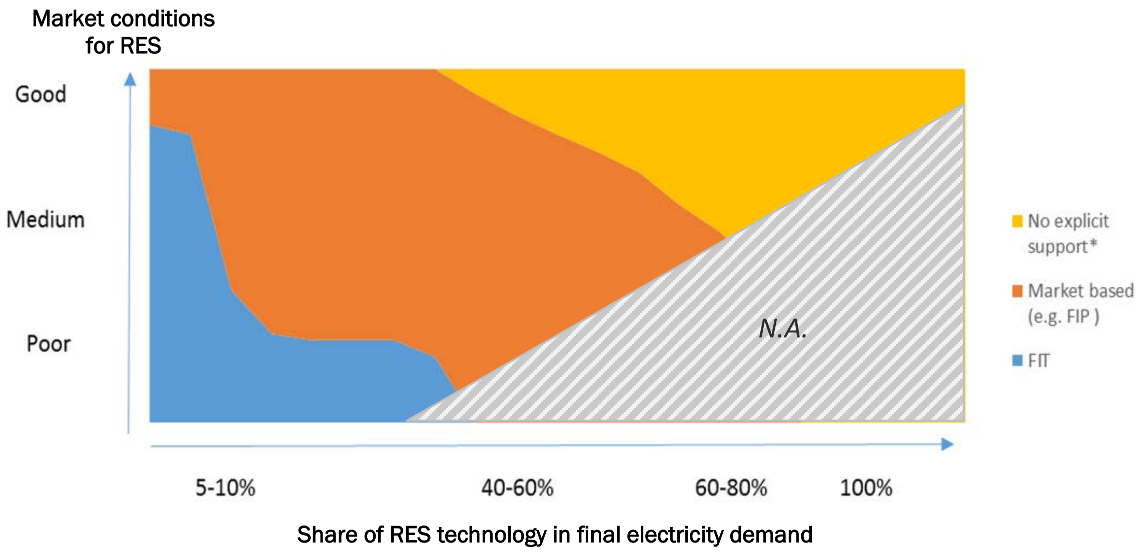
Evolution of RES support schemes up to 2020

The Market4RES consortium anticipates that RES support schemes need to be adapted based on two dimensions:

- **The level of RES penetration:** the more RES are already installed, the less public support is necessary as the industry matures and integrates into the market ;
- **The market conditions:** the more the markets are fit for RES generation, the less RES capacities need financial support.

These interrelations are graphically represented in ***Figure 1***, in which the RES share is represented on the horizontal axis, and market conditions represented in a simplified manner (good, medium or poor) on the vertical axis. The numbers in the figure are only indicative.

Figure 1. *Support schemes adapted to market conditions and RES penetration*



**Explicit support is needed when other complementary markets do not function correctly and when environmental externalities are not internalized.*

The Market4RES consortium considers that Feed-in-Tariffs are the best support mechanism in case of low RES penetration (new technologies, or recent use of technologies within a new market), or poor market conditions (or both). This was the typical situation for many countries in the EU at the beginning of the liberalisation of the electricity sector. **Market conditions need to evolve to allow for the sustainable growth of renewables: this will be detailed within upcoming Market4RES reports D6.1.2 (up to the 2020 horizon) and D6.2 (post 2020).**

Regarding the evolution of RES support schemes themselves, the detailed setting of premium schemes, and the configuration of tenders allocating the premium to new RES installations, should be designed very carefully. The Market4RES project is providing several recommendations to design the tenders, with a focus on the 3 main stages:

- "Before the auction": to deploy volumes and ensure visibility for investors,
- "During the auction": to set applicant-friendly design parameters for cost-effective auctions,
- "After the auction": to ensuring project fulfilment.

Deployment of demand flexibility

Background

As stated in Market4RES report D2.1 [2], *"demand participation in markets could result in a decrease in system operation costs, an increase in the level of integration renewable generation, thus paving the way for higher RES-E penetration levels, and an increase in the level of* *competition, thus contributing to a reduction in the level of prices, among other benefits"*. Still, the need for demand response has not always been so urgent. Nowadays - and even more importantly within the future electricity system integrating higher shares of variable renewables, demand response (as well as other flexibility means) is increasingly needed, because the generation fleet will decreasingly be able to follow the load unless mechanisms are in place to ensure a considerable over-capacity. Rather, the load will perhaps more and more follow the non-dispatchable generation by being decreased or shed during low-production hours and possibly increased during high-production hours. Demand response shall therefore be one of the central topics to be addressed by the European Commission in its legislative proposals to redesign the electricity market, expected in the second half of 2016.

Development of demand response in Europe

Different approaches can be considered to make demand flexibility (or demand-side response – DSR) able to be valued efficiently in short term energy markets. Consumers response to prices can be valued either implicitly through the contract with their supplier[3], or explicitly through their own participation in the market possibly through an aggregator that bids on their behalf. For each of these two main options, different designs can be applied.

Implicit demand response from big, industrial consumers has been developed for long in most European countries. In some other countries, residential consumers have also been an important way of implicit DSR development like in France for instance, where electricity heating has been promoted in the same time as implicit residential DSR. What is really new, is the development of explicit demand response, thanks to the revolution in data technologies, which implies a lower cost for smart meters. With the new affordable technologies in smart metering, DSR operators can now develop offers for small consumers or small industries and be able to value it explicitly on the markets. This new liberty creates competition between suppliers and DSR operators on the demand response market. This new competition will develop the offers for the benefit of the electricity system. Moreover, the development of smart metering and of new index will develop the opportunities for DSR design for the suppliers. At the same time, commercial development of residential demand response has started in a limited number of countries.

Assessment by the Market4RES project

The Market4RES project proposes a review of detailed market design options for demand response and of the barriers to its development.

- It appears that all options available, both implicit and explicit schemes, should be allowed to provide consumers with large flexibility. Implicit schemes are the simplest ones and reasonably efficient. However, under these schemes, agents cannot compete to access DSR resources. Then, the introduction of independent load aggregators should also be considered as an option. The transfer of funds between aggregators and suppliers should

[3] **Or retailer: these two terms are considered as synonymous in this report.**

be set by an independent entity to guarantee fair treatment of both of them and in order to promote efficiency in market functioning.

- In terms of barriers to the development of demand response, economic barriers are important ones. One first prerequisite for the deployment of DSM services is that it is efficient from a net social benefit point of view, i.e. extra revenues, or benefits, resulting from DSM are larger than implementation costs.

The Market4RES project has studied in a quantitative manner the impact of demand flexibility on the outcomes of short-term markets. It appears *inter alia* that demand flexibility has a major impact on the average daily spread (difference between the maximum price of the day within a given market area and the minimum price of the same day and market). Therefore, a sufficient average daily spread is needed to allow for the development and profitability of demand response, and at the same time demand flexibility deployment tends to make the daily spreads decrease. Also, the cross-border spreads (difference in market prices between adjacent countries) would drop with the large-scale deployment of demand response.

Conclusions for demand participation in short-term markets

Demand response is clearly a key in the future market design allowing for a massive integration of renewables. If the 2030 generation fleet will not be flexible enough to follow consumption, the load will have to adapt itself. Thus, DSR development could be an appropriate answer to RES deployment. Nevertheless, DSR development will meet these ambitious objectives only if some barriers disappear, such as: deployment of smart metering, deployment of effective and affordable communication means between consumers and DSR operators, development of control methods, and establishment of a fair competition between suppliers and DSR operators.

Benefits of demand-side participation in short-term markets have been quantified by the Market4RES consortium. Those should range between 458 and 2,161 million of euros per year within the 11 countries included in the scope of our quantitative analyses, depending on the different scenarios considered (renewable penetration level, fuel cost, CO_2 price, etc.) and on the level of deployment of demand response. Still, additional benefits like demand participation in reserve markets and avoided investments in peaking units and in network infrastructures, would also need to be quantified in a transparent and rigorous manner.

To make sure that demand response can kick-off at large scale as soon as the economic conditions are met (in particular, sufficient price spreads are needed), the technical obstacles should be removed. This concerns in particular the design of the products traded on the wholesale electricity markets. Many design options are available and need to be followed to develop the potential benefits of DSR. It can be valued on the energy market, on the balancing market, on the capacity market, and for ancillary services. For DSR investors, it is important to touch most of these markets with the same IT system. The integration of DSR in the design of these markets is a heavy responsibility and challenge for DSOs and TSOs in the next decade.

Next steps

In the present report D6.1.1, we have summarized and drawn conclusions from a significant part of the work done within the Market4RES project since 2014. Within the first work stream of the project (focused on short-term objectives regarding power market design), we have discussed in detail two topics of utmost importance in terms of market development. For this we have used outcomes of previous work packages of the project, namely WP2, WP3 and WP4 (see glossary section, page 7).

The present report D6.1.1 will be supplemented by other concluding reports, illustrated by ***Table 1*** below.

Table 1. *Organisation of concluding Market4RES reports (WP6 deliverables)*

Market design aspects	WP6 deliverable	Based on
Workstream 1: short-term objectives		
RES support schemes design up to 2020	D6.1.1	WP2, WP3, WP4
Participation of demand in short-term markets		
Other design features of short-term markets	D6.1.2	WP2, WP3, WP5
Workstream 2: long-term objectives		
New market designs for RES beyond 2020	D6.2	WP2, WP3, WP5
Design of capacity remuneration mechanisms	D6.3	WP2, WP3, WP5
Participation of demand in long-term markets		

1 INTRODUCTION

1.1 Concluding Market4RES: focus on the first Work Stream of the project

The Work Package 6 (WP6) is the concluding part of the Market4RES project. In this WP, the results from previous work packages are analysed and gathered into a set of conclusions and recommendations. Its major objective is therefore to recommend the steps towards a practical implementation of policy, legislation and regulations for the renewable electricity generation in order to secure a robust evolution of the EU Target Model (TM) beyond 2020.

The Market4RES project addresses market design issues via two separate work streams:

- **Work Stream 1:** Assuming the current generation fleet as an input and current implementation status of the target model, the focus is on determining appropriate, yet novel, instruments (and their subsequent accompanying national energy policies) for increased renewable electricity generation in support of the 20/20/20 targets;
- **Work Stream 2:** Assuming the future generation fleet (beyond 2020) as a result of current market designs, and taking into account possible future changes in market design beyond the existing TM, the focus is on developing necessary additions or complementary instruments to the current design, which will induce investment incentives and phase out support schemes in the long term without compromising system adequacy or security of supply.

In the present report D6.1.1 and in its follow-up D6.1.2, the focus is on the first work stream of the project. It therefore addresses the 2020 horizon, both in terms of generation fleet and in terms of possible market designs. It deals only with energy markets, with a special focus on day-ahead markets.

Upcoming reports D6.2 and D6.3 will address the second work stream of the project, with focus on longer-term horizons (2030 and beyond) and on long-term energy markets and capacity markets.

1.2 Purpose of this report

The purpose of the present report D6.1.1 is to deliver recommendations and roadmaps about two specific aspects of the current market design:

- **Short-term effects of RES support schemes:** Given the obligation to move towards market-based schemes, what will be the impacts of this change on short-term markets? Which proportion of wind and solar capacities should be concerned by these new schemes? How the market-based schemes shall be configured?

- **Participation of demand in short-term markets:** Demand response is seen as a solution to many problems, but has not been deployed yet on a large scale.[4] What will be the real impacts of such deployment? Which measures could be put in place to ensure that the benefits exceed the costs?

For both topics, the recommendations that are being delivered in this report are based on work performed within previous work packages of the project, namely WP2, WP3 and WP4:

- WP2 has analysed the market distortions caused by RES support schemes, and the lack of participation of demand in the different market segments (see [2]);
- WP3 has studied in a qualitative manner developments affecting the design of short-term markets, including RES support schemes and demand response (see [3]);
- WP4 has studied in a quantitative manner the impacts on short-term markets of different options regarding RES support schemes and demand response, at the 2020 horizon (see [4], [5] and [6]).

This report will be supplemented by another deliverable D6.1.2, which will give recommendations about other aspects in relation with short-term market design (timing of day-ahead markets, features of balancing markets, etc.). It will also be based on the work performed within previous work packages of the project, except WP4 which is focused on the topics addressed in the present report D6.1.1.

1.3 Structure of this report

This report is structured as follows.

Chapter 2 provides the Market4RES consortium vision about RES support schemes and their evolution up to the 2020 horizon. First, the general framework for RES support schemes is set (section 2.1), including the rationale for RES support, a review of the main design options for support schemes and the recent EC Guidelines requesting the market integration of renewable production. Then, a qualitative assessment of RES support schemes is given with a particular focus on the process towards market integration of RES (section 2.2). The results of a quantitative analysis performed in the market4RES project about the impacts of RES support schemes on short-term market outcomes are also reminded (section 2.3). Finally, section 2.4 provides the views of the Market4RES consortium on the roadmap towards market integration of RES: an overview of the general roadmap is first given (subsection 2.4.1), and a focus on the possible design options available at 2020 is made in subsection 2.4.2.

Chapter 3 provides a comprehensive vision of demand flexibility in Europe. First, the general framework of demand flexibility is set (section 3.1), including the rational for demand flexibility development, a review of existing market design options for demand participation in short-term markets, the current status of the development of demand response in Europe and a review of the

[4] Consumers are typically exposed to general changes in price levels over some time, which they respond to. However, for e.g. within-day or real-time adaption of demand based on market prices, there are currently no large scale examples.

barriers to its further development. In section 3.2, a qualitative assessment of the different design options for demand participation in short-term markets is given based on previous work in the project. Then the results of a quantitative analysis of the impacts on short-term market outcomes of the large-scale deployment of demand flexibility are presented and a comparison with other studies is carried out (section 3.3). Finally, in section 3.4 conditions for the deployment of demand participation in short-term markets are listed, with specific views for each type of involved stakeholders (network operators, market players, consumers) and a conclusion is provided to foster the deployment of demand response in Europe.

Chapter 4 summarizes the conclusions of the present report and explains the articulation with other Market4RES WP6 deliverables.

In **Chapter 5** a list of 35 references is given covering the two topics addressed by this report.

2 RES SUPPORT SCHEMES

In this chapter, we provide a comprehensive vision of RES support schemes in Europe, with a particular focus on the gradual move towards market-based schemes. This vision is based on the work carried out by the Market4RES consortium during the last two years. It encompasses a review of existing support schemes, a qualitative assessment of these and a quantitative analysis of the impacts on short-term markets of the gradual move from Feed-in-Tariffs to Price Premium schemes. This work allows the Market4RES consortium to propose a roadmap for the future evolution of RES support schemes.

2.1 General framework

2.1.1 Rationale for RES support schemes

Energy markets alone could not deliver the desired level of renewables in the EU, meaning that some support has been needed to stimulate investment in renewable energy. At least two types of measures have been necessary: priority dispatch and financial support.

Priority dispatch

Priority dispatch is the obligation on transmission system operators (TSOs) to schedule and dispatch energy from renewable generators ahead of other generators as far as secure operation of the electricity system permits. Member States can either explicitly mention priority dispatch in national legislation or, alternatively, priority dispatch is considered to be implicitly given in support systems which include a purchase obligation, such as feed-in tariffs.

The rationale for the introduction of this regulatory tool is that the current market structure and rules were not designed with variable energy generation technologies in mind. The response to price signals from these generators is different, based on availability of its fluctuating source, which they cannot control. If in addition, there is a lack of transparency in operation and curtailment rules, RES-E generators have an additional market risk (uncertainty on volumes sold), which they need to be hedged for. In this sense, priority dispatch significantly reduces risks for RES-E generators as new market entrants by:

- ensuring that its energy is sold to the market;
- guaranteeing its in-feed to the grid when it is available;
- hedging RES-E energy generators from the so-called volume risk[5], that could stem from non-system security-related curtailments.

[5] Next to volume risk, investors perceive balancing and price risks as determinant for RES-E generation projects financial viability.

Wind and solar PV energy in particular, having variable output with very low marginal costs, risk being the first to be curtailed in power systems with low flexibility[6]. As curtailing variable generators would be the easiest solution to solve grid issues in such systems, the RES-E Directive requires system operators to reduce curtailment of RES-E generation.

In mature markets with high penetration levels of RES-E, future regulatory frameworks and power market design can consider increased exposure of RES-E generators to market risks, including progressively phasing out priority dispatch and/or developing a more market-price responsive mechanism in mature markets with high penetration levels of RES-E (see [7]).

Overall, priority dispatch has been an important tool to facilitate the integration of RES-E into the power system. The lack of transparency in curtailment rules of new variable RES-E generation in particular, makes priority dispatch in many Member States a policy-driven solution that ensures that its intrinsic characteristics are not a barrier to its exploitation. In this sense, well described and clear rules for curtailing RES-E generation would reduce risks for these generators as new market entrants, specifically by providing compensation rules for non-system security related curtailments.

Financial support schemes

Traditionally, fossil-fuel based technologies and nuclear power have enjoyed a wide range of public support, for example in fuel extraction and production. Moreover, external environmental costs were not fully internalized (global, regional or local). Considerable progress has been made for local and regional emissions with standards on technologies and abatement measures for e.g. SO_2, VOC, NOx and fine particles. Moreover, with the emission permit system in the EU, fossil fuel power generation gets an extra cost corresponding to the marginal cost of keeping total emission levels below a defined ceiling. Still, there are several reasons for providing financial support to renewable generation:

- Renewable power generation still have a considerable potential for further technological development through learning-by-doing, and this is a positive externality. Renewable energies need financial incentives to develop, to increase to significant market volumes and to foster technological innovation, until they become mature enough to compete with conventional generation fed into the grid.
- The defined ceiling in EU ETS and the corresponding permit price may not represent the true environmental cost of emissions because the ceiling is set too high. Renewable energy together with e.g. CCS and energy efficiency measures, are *enablers* for making Europe less dependent on fossil fuels. Development and implementation of these technologies

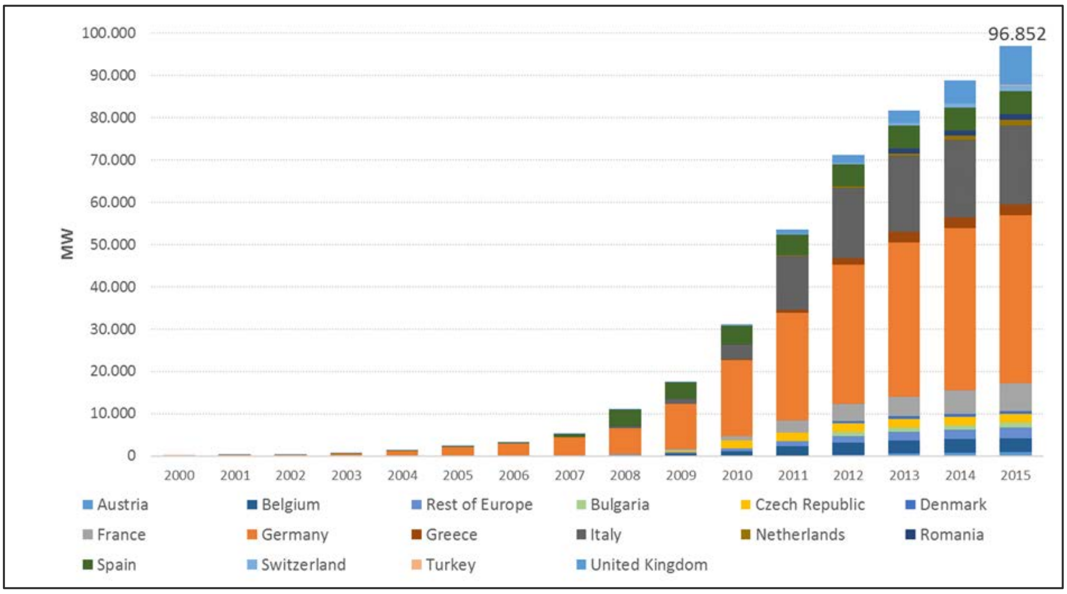
[6] The level of flexibility in power systems is subject of continuous research and debate in the context of integration of large amounts of wind and other RES-E. The IEA defines both, technical and market sources of flexibility that facilitates RES-E integration. Technical sources include flexible generation capacity, interconnection capacity, demand side response and storage. Market sources of flexibility include aggregation of distributed generation, trading electricity close to delivery time, large balancing areas and smart network operation. IEA (2011) Harnessing Variable Renewables.

will make it simpler for policy makers to set more ambitions environmental targets in the future e.g. through reducing the ceiling within EU ETS.

- Renewable energy production in Europe gives reduced risks caused by dependency of imported energy.
- There are specific targets for RES shares in energy consumption in the EU.

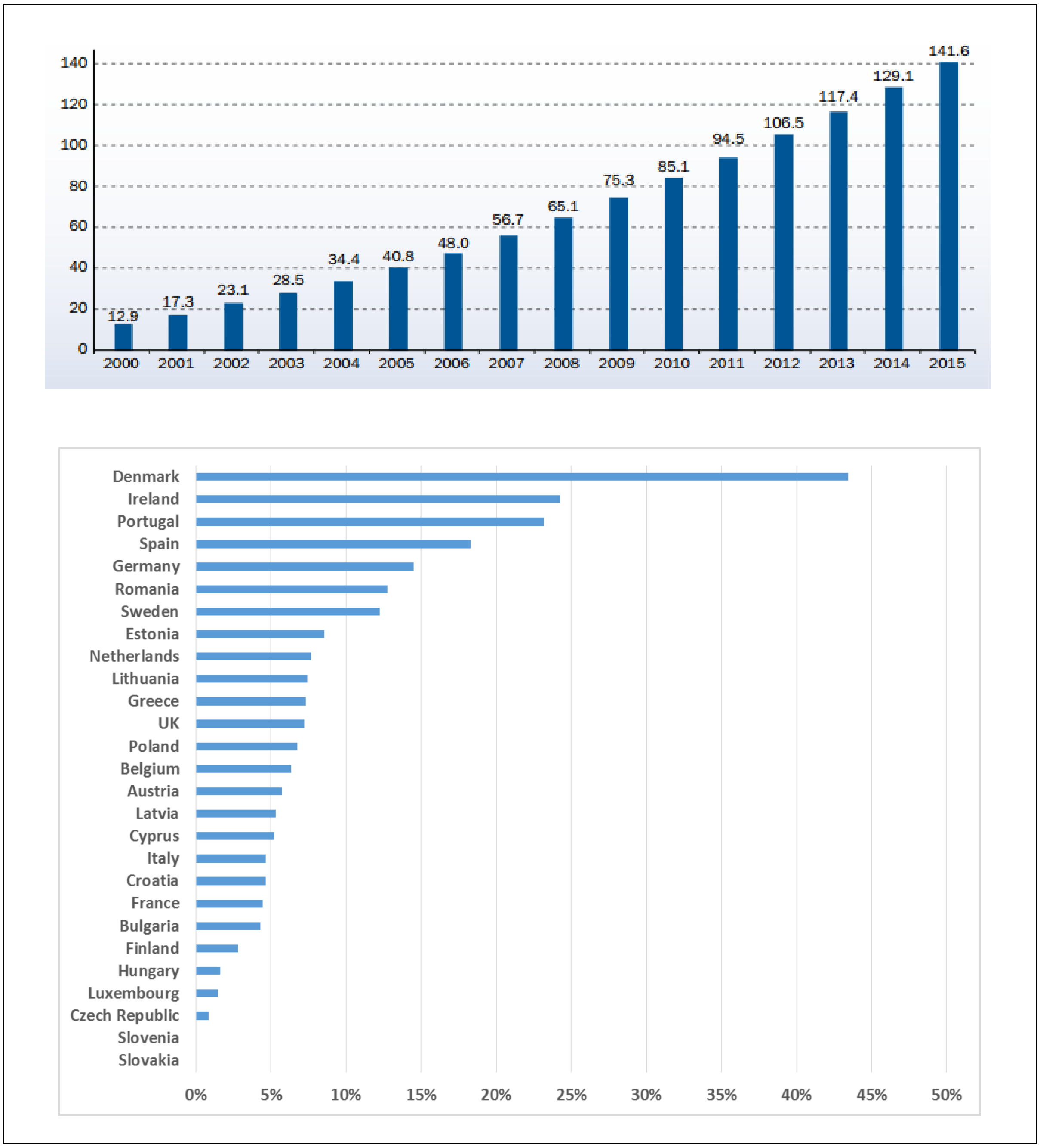
In Europe, in most cases the financial support to renewable generation has initially been granted in the form of feed-in-tariffs (FiT) which guarantees a fixed price per unit of electricity generated (MWh) fed into the grid over a specific time period (see section 2.1.2). This support has allowed triggering the development of RES-E generation capacities – mainly from wind and solar sources – and has led to significant generation capacities in Europe, as shown on *Figure 2* and *Figure 3* (see also [2]).

Figure 2. *Evolution of European PV cumulative installed capacity 2000-2015*



Source: SolarPower Europe

Figure 3. *Cumulative wind power installations in the EU (GW) and Wind power share of total electricity consumption in EU Member States*



Source: Wind Europe

Ultimately, the objective of the RES-E industry is to be competitive in a liberalised electricity market, and to deliver the benefits of this emission-free energy to consumers. Regulatory incentives for more mature RES-E power generation technologies would not be needed with a fully functioning electricity market and full internalisation of external costs. This necessary transition is discussed further within the next sections of this chapter.

2.1.2 Review of existing RES support schemes

In the Market4RES reports D3.1 and D3.2 addressing the developments affecting the design of long- and short-term markets [8] [3], options for RES support have been described. Their impacts on short-term markets have also been assessed in a qualitative manner.

Options considered in [8] and [3] are also described below.

1. **Long term clean capacity auctions:** This is a system of long term generation capacity auctions, whereby support to a predefined amount of RES generation capacity of a certain technology to be installed (being the amount decided by authorities and the technology that, or those, that need to be supported to get mature) results from bids accepted in the auction. The marginal capacity bid accepted would be setting the price paid for each unit of generation capacity installed.
2. **Long term clean energy auctions:** Remuneration conditions affecting the compulsory supply of a certain block of clean energy (predefined amount of it) are set through an auction process taking place in the long term.
3. **Net metering of demand and generation per network user to compute regulated charges:** Net power production and demand over certain periods of time are netted out in order to compute the level of regulated charges paid by the corresponding network user. Thus, a sort of subsidy can be deemed to be applied to the latter.
4. **Feed-in-Tariffs (FIT) with Regulated Prices:** Administratively set tariff for every MWh produced over a given period.
5. **FIT with auction:** Tariff is provided for a given period, the level is the result of an auction taking place in the long term.
6. **Feed-in-Premium (FIP) regulated with no price cap and floor:** Administratively set premium on top of market price for every MWh produced over the given period. [7]
7. **FIP regulated with overall price cap and floor:** Administratively set premium on top of market price for every MWh produced over the given period. There is a maximum and a minimum level for the overall price resulting from adding up market price and premium.
8. **FIP resulting from an auction with no price cap and floor:** Premium on top of market price is set for a given period, but the level of the premium results from an auction.
9. **FIP resulting from an auction with overall price cap and floor:** Premium on top of market price is set for a given period, but the level of the premium results from an auction. There is a maximum and a minimum level for the overall price resulting from adding up market price and premium.

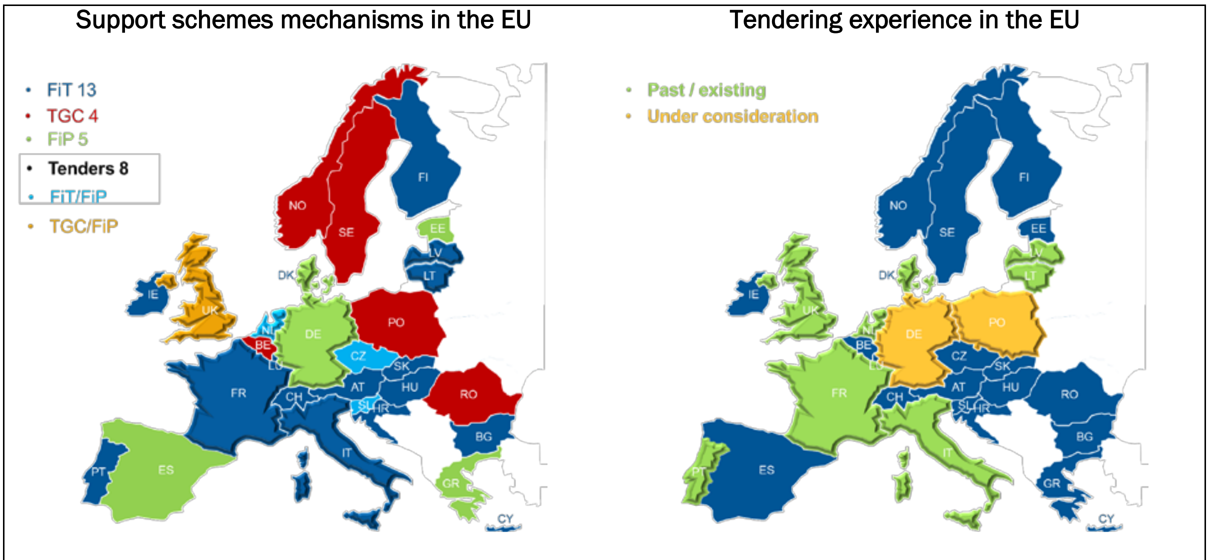
[7] Within Market4RES deliverables D4.1 [4] and D4.2 [5], this support scheme is referred to as Price Premium (PP).

10. **Certificate Schemes with Quota:** Introduction of a quota for several years per renewable technology. Electricity suppliers would be either obliged to produce a certain volume of green energy, or to buy an equivalent volume of "green" certificates corresponding to electricity produced by RES producers.
11. **No support (conventional market remuneration):** No support mechanism. RES producers would sell at the best price offered in the market.
12. **Support conditioned to the provision of grid support services:** In this case, support to RES generation, which tend to be of a FIP or FIT type, is largely contingent on the provision of voltage support service by this RES generation. RES generation not providing voltage support earns some basic support which is much lower than that earned by RES generation providing voltage support. As far as authors are aware of, this scheme has only been implemented in Germany.

Case studies about several of these support options are provided by CEER in [9].

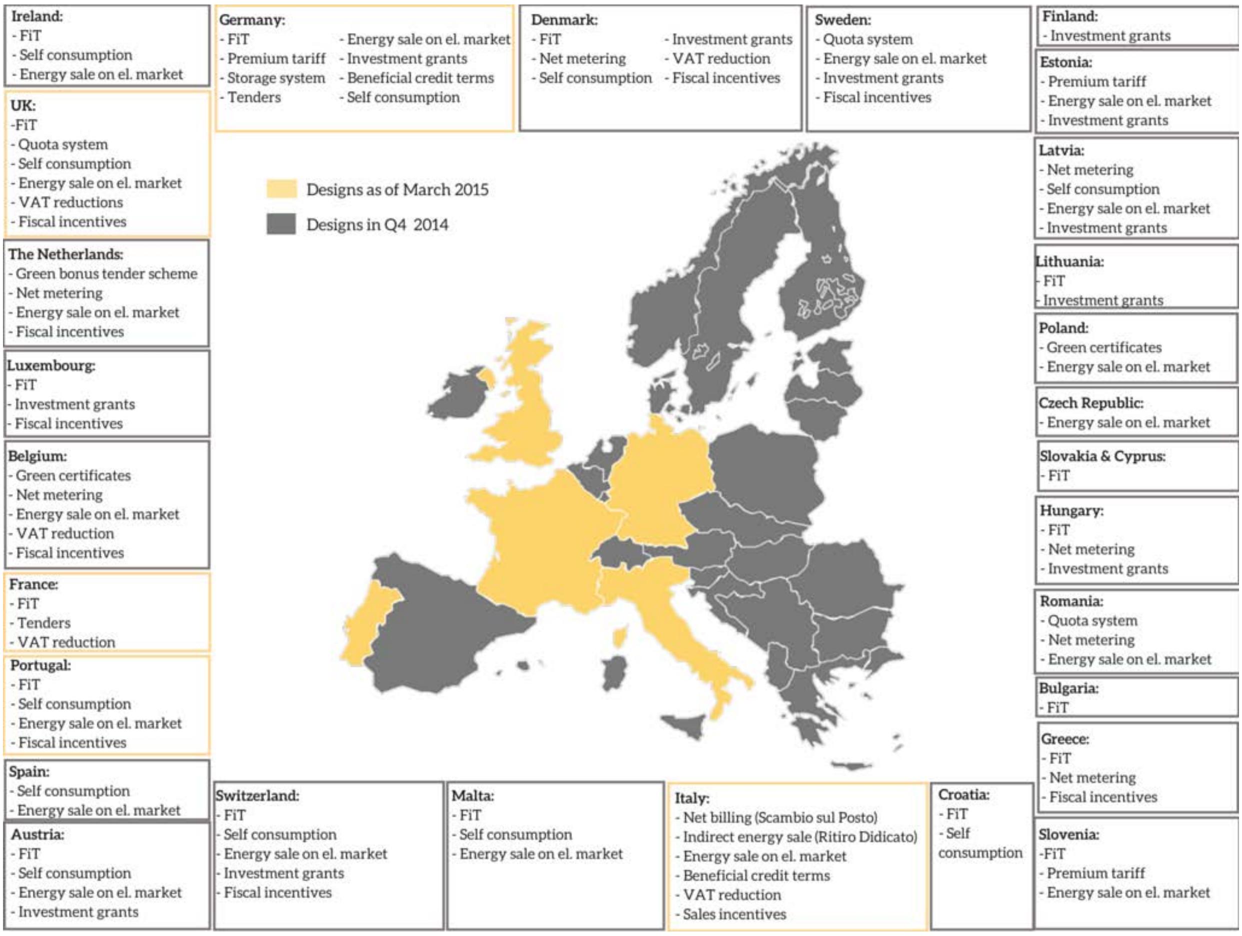
Figure 4 below shows the support schemes applicable to new wind capacities and the experience in Europe with tendering procedures (categorized as auctions in the above list). *Figure 5* provides an overview of the support schemes currently applied in Europe for solar generation (both for existing and for new capacities).

Figure 4. *Support schemes applied to new wind capacities (update November 2015)*



Source : WindEurope

Figure 5. *Support schemes applied to solar capacities in the EU (update March 2015)*



Source: SolarPower Europe

2.1.3 Moving towards market integration: the new Environmental and Energy State Aid guidelines

The European Commission's new Environmental and Energy State Aid guidelines [10] have replaced the existing guidelines on aid for Environmental protection that entered into force in 2008. The new guidelines aim at defining criteria allowing EU Member States to design state aid measures that contribute to reaching their 2020 climate targets and provide sustainable and secure energy, while ensuring that those measures are cost-effective for society and do not cause distortions of competition or a fragmentation of the Single Market. The new guidelines will be in force until the end of 2020.

As pointed out by the EC [11] *"In recent years, renewable energy sources have been heavily supported with fixed tariffs. This has encouraged enormously the growth of renewables in the energy mix and has put Europe on track for meeting its 2020 renewables target. However, this type of support has also sheltered them from price signals and has led to market distortions. [...] As technologies mature and their production reaches a substantial share of the market, renewable energy production can and should react to market signals, and aid amounts should respond to falling production costs."* [8]

The new guidelines therefore aim to better integrate renewables into the internal electricity market in a gradual way, through the gradual introduction of market based mechanisms.

"In order to incentivise the market integration of electricity from renewable sources, it is important that beneficiaries sell their electricity directly in the market and are subject to market obligations. The following cumulative conditions apply from 1 January 2016 to all new aid schemes and measures:

- a) *aid is granted as a premium in addition to the market price (premium) whereby the generators sell its electricity directly in the market;*
- b) *beneficiaries are subject to standard balancing responsibilities, unless no liquid intra-day markets exist;*
- c) *measures are put in place to ensure that generators have no incentive to generate electricity under negative prices."*

The new guidelines also foresee the gradual introduction of competitive bidding processes for allocating public support, while offering Member States flexibility to take account of national circumstances (par 126)

"From 1 January 2017, the following requirements apply:

[8] **The market distortions mentioned in the Guidelines have been analysed in Market4RES deliverable D2.1 [2].**

Aid is granted in a competitive bidding process on the basis of clear, transparent and non-discriminatory criteria[9]*, unless:*

- *Member States demonstrate that only one or a very limited number of projects or sites could be eligible; or*
- *Member States demonstrate that a competitive bidding process would lead to higher support levels; or*
- *Member States demonstrate that a competitive bidding process would result in low project realisation rates (avoid underbidding).*

If such competitive bidding processes are open to all generators producing electricity from renewable energy sources on a non-discriminatory basis, the Commission will presume that the aid is proportionate and does not distort competition […].

The bidding process can be limited to specific technologies where a process open to all generators would lead to a suboptimal result which cannot be addressed in the process design in view of, in particular:

- *the longer-term potential of a given new and innovative technology; or*
- *the need to achieve diversification; or*
- *network constraints and grid stability; or*
- *system (integration) costs; or*
- *the need to avoid distortions on the raw material markets from biomass support."*

Therefore, this new legal framework will lead to profound changes in the support to renewable energy sources. Such changes are likely to have significant impacts on RES generation and possibly on the whole power system. In order to be well prepared to these changes and to allow making the correct choices when designing the new support mechanisms, there is a need to assess (in a qualitative manner and when possible, in a quantitative manner) the effects of the different schemes compatible with this new framework.

With regards to small producers of renewable energy, small installations or technologies in an early stage of development can be exempted from participating in competitive bidding processes. The Guidelines define small installations as those producing less than 6 MW of wind power (or 6 generation units), or 1 MW of power from other renewable sources, such as solar or biomass. *"Aid may be granted without a competitive bidding process as described in paragraph (126) to installations with an installed electricity capacity of less than 1 MW, or demonstration projects, except for electricity from wind energy, for installations with an installed electricity capacity of up to 6 MW or 6 generation units"*.

[9] So the support is no longer granted administratively but rather through a genuine competitive bidding process on the basis of clear, transparent and non-discriminatory criteria.

2.2 Qualitative assessment of RES support schemes

Within the Market4RES project, the different options for RES support listed in section 2.1.2 have been qualitatively assessed in terms of both their long-term effects (see [8]) and their short-term effects (see [3]).

These assessments have been carried out against a list of performance indicators, which were defined in WP3, covering efficiency, effectiveness, robustness, implementability and fairness aspects.

The conclusions of these assessments are as follows:

- Regarding the long-term [8], *"the most promising RES support mechanisms are those with a **market nature**, namely **long-term clean energy or capacity auctions** and Feed-in Tariff or Feed-in Premium **auction schemes**. These mechanisms result in the most cost-competitive RES generation that is compatible with the achievement of RES deployment objectives being installed in the system and could be accepted by authorities and stakeholders."*
- Regarding the short-term [3], *"RES support schemes applied should allow an effective and efficient functioning of short term markets. This is the case of **long term clean capacity auctions**, mainly, but also, to some extent, that of **long term clean energy auctions**, **certificate schemes and feed-in-premium (FIP) ones based on auctions**. The distortion of efficient short term prices caused by long term capacity auctions is negligible, and it may be limited for the rest of these schemes. Being market schemes that make revenues of RES operators depend on operation decisions, these support options foster the participation of RES generation in short term markets and are difficult to be manipulated by authorities. Lastly, Certificate schemes allocate the costs of RES support to agents responsible for the need to deploy this generation, i.e. consumers. These are the preferred RES support schemes considering also their long term effects, since they are effective in achieving the deployment of RES generation, and this should take place at low cost, since also the long term signals they produce are efficient."*

This analysis confirms the need to move towards market-based remuneration schemes for renewable generation.

2.3 Quantitative analysis and comparison of the impacts of RES support schemes on short-term markets: Impacts of the gradual move from Feed-in-Tariffs to Price Premium on short-term market outcomes

Here we refer to a Market4RES study carried out with the OPTIMATE prototype tool. The methodology implemented and the specifications of the study are described in the Market4RES reports D4.1 [4], and the detailed results are presented in the Market4RES reports D4.2 [5].

OPTIMATE is a numerical simulation platform[10] designed to compare wholesale short-term electricity market architecture options integrating massive variable electricity generation in Europe, complying with the three EU energy pillars (economic efficiency, climate policy and security of supply). The OPTIMATE prototype platform was developed during an EC-funded FP7 project (2009-2012) [11] under the technical direction of RTE. For the Market4RES studies, only the day-ahead market process is taken into consideration in the simulations (intraday and balancing processes are not addressed because the corresponding OPTIMATE modules have been finalized only recently).

The purpose of the study is to complement the qualitative analysis summarized in section 2.2 by a quantitative analysis, assessing the impact on short-term market outcomes of the foreseen evolution in RES support schemes from Feed-in-Tariffs (FiT) to market-based schemes as foreseen by the European Commission in [10] and summarized in section 2.1.3.

2.3.1 RES support options studied

The study does not take into account all support options presented in 2.1.2 and assessed in [8] and [3], since only short-term energy markets are modelled within OPTIMATE: for example, long-term auctions cannot be simulated. Therefore, three support options are modelled:

- **Feed-in-Tariff (FiT)**, which guarantees a fixed regulated price per unit of electricity generated (MWh) fed into the grid over a specific time period (whatever the electricity market price) and encompassing a legal requirement that subsidised energy has priority access to the network (priority dispatch). Hence, under the FiT scheme, the remuneration of RES producers is always guaranteed irrespective of the market price in the OPTIMATE model. This means that RES production is integrated as a "must-run". Since within OPTIMATE the whole generation is offered to the day-ahead market, this is modelled as if RES producers submitted bids at the minimum authorised price (i.e. - 500 €/MWh). FiT is the support scheme, which is currently applied in most EU countries, both for wind and for PV. Since in most cases a change in support schemes cannot be retroactive, FiT will continue to be applied to existing RES units for years even if Price Premium schemes are introduced for new units.
- With a **Feed-in-Premium (FiP)**, also called **Price Premium (PP)** scheme, RES producers receive a fixed regulated premium (extra bonus) over the spot electricity market price for the feed-in of renewable energy. They have no priority dispatch. Under this scheme, RES producers have positive income as long as the market price is not more negative than the premium amount. As explained above, price premium is the target set by the new EC State Aid Guidelines. Here, we consider a fix premium (non-floating) with no cap nor floor for the sum of electricity price plus price premium.

[10] See http://www.optimate-platform.eu/.
[11] "An Open Platform to Test Integration in new MArkeT designs of massive intermittent Energy sources dispersed in several regional power markets" (grant agreement N° 239456).

- **No support schemes**: studying the impacts of this option will allow isolating the impacts of RES support schemes on market outcomes.

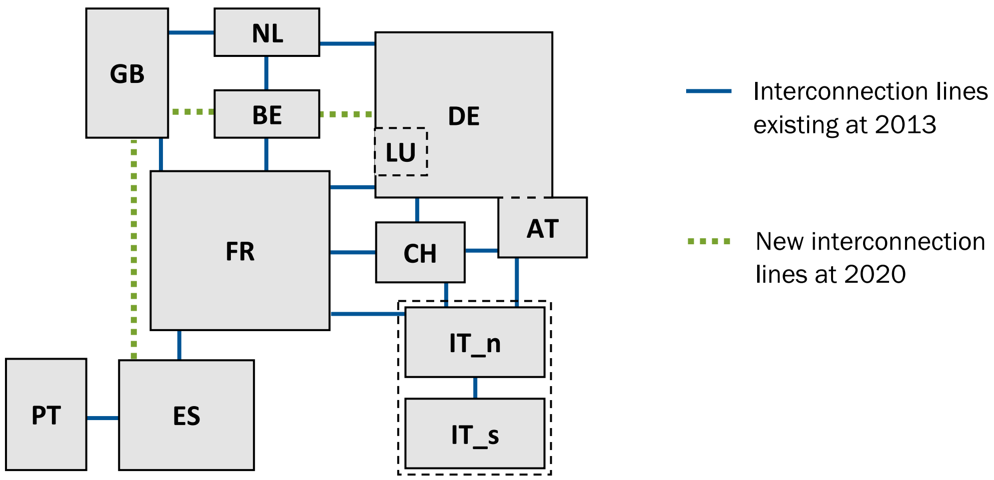
2.3.2 Specifications of the study

Three scenarios are considered within the study, in order to assess the sensitivity of the impacts of each option with regard to the main features of the power system (installed generation capacities, demand level, network capacities, etc.). Each scenario is described in a detailed manner in [4] and can be summarized as follows:

- The **2013 scenario**, also called **reference scenario,** mimics the current situation of the power system.
- The **2020 standard scenario** mimics the situation of the power system, which can reasonably be expected at 2020. It is based on official publications such as the National Renewable Energy Action Plans (NREAPs) [12], ENTSO-E's Ten-Year Network Development Plan (TYNDP) 2014 [13], ENTSO-E's Scenario Outlook and Adequacy Forecast (SO&AF) 2014-2030 [14], etc.
- The alternative **2020 RES+ scenario** is derived from the 2020 standard scenario. Within this scenario, RES installed capacities result from doubling the increase in RES installed capacities from 2013 to 2020. In other words, they are built by doubling the spread between the 2013 and 2020 standard scenario, as if the rhythm of installation of new capacities was twice as expected. In addition, these new RES capacities replace some thermal capacities, the latter being both more flexible, and more costly through an increased CO_2 cost (see [4] for all details).

All scenarios are based on a geographical scope covering 11 countries as depicted in ***Figure 6*** below (see [4]).

Figure 6. *Geographical scope of the studies*



For each of these scenarios, two cases have been considered as presented in *Table 2*:

- A default case in which no RES support schemes is applied: corresponding short-term market outcomes represent therefore default values against which the impacts of RES support schemes can be assessed;
- A case in which RES support schemes are applied, according to a combination of Feed-in-Tariffs and Price Premiums (see details in next section).

Table 2. *Combination of scenarios and RES support schemes*

Studies	#	Scenarios	RES SS
Default cases	1	2013	None
	2	2020 standard	None
	3	2020 RES+	None
Study on RES support schemes	4	2013	RES support schemes applied in 2013
	5	2020 standard	Foreseen RES support schemes at 2020: • 2013 support schemes for capacities existing in the 2013 scenario, • Price Premium for all new capacities
	6	2020 RES+	

Note that our set-up for studying RES support in 2020 is based on what we consider as reasonably realistic for 2020, which do not include FiT for new capacities.

2.3.3 Configuration of RES support schemes

For each scenario, RES support schemes have been estimated and simplified.

- For the reference 2013 scenario, this assessment is based on actual RES support schemes in force in the different countries, with some simplifications:
    - Regarding the support schemes applied to PV generation, calculating the average support is very complex because market segmentation differs in the different countries, and support has changed from one year to another. With the support of SolarPower Europe, it has therefore been decided to consider an average feed-in-tariff in all countries of 250 €/MWh. Only in Germany a significant share of PV installed capacities is supported by a price premium scheme (4,375 MW[12], i.e. 12% of total installed capacities). The premium is at about 107 €/MWh (average value taking account of all market segments, from residential to ground-mounted installations).
    - The support schemes currently applied to wind installed capacities have been provided by WindEurope. Simplifications have been applied to the initial input data:

[12] See www.germanenergyblog.de/?p=17680 and www.netztransparenz.de.

for example, Tradable Green Certificates (TGC) are approximated with a Price Premium; for offshore and onshore PPs and FiTs, average values, weighted by the installed capacities, are calculated.

- For the 2020 scenarios, necessary simplifications have also been applied:
  - Firstly, we consider that the support schemes for the units already present in the 2013 scenario do not evolve: we apply no indexation scheme to the current FiT, and we neglect the possible decommissioning of RES units as well as the possible end of some FiT contracts;
  - Secondly, we consider that all units built between 2013 and 2020 are subject to a Price Premium.
- For assessing the price premiums (PP) at 2020, the following method has been applied:
  - The levelized cost of electricity (LCOE)[13] at 2020 provided by IEA Technology Roadmaps is considered as the best estimate for the 2020 wind and solar production costs;
  - To the LCOE is added an acceptable profit for RES producers: 7% is considered;
  - The PP is obtained by the difference between the average market price at 2020 calculated by OPTIMATE without any support scheme (default case) and the LCOE, taking account of the 7% profit for RES producers.

This method is close to the actual way in which price premiums are defined by Member States' authorities, as explained in CEER report "Key support elements of RES in Europe: moving towards market integration" [9]. Public authorities face two challenges in applying this method:

- Assessment of the LCOE: As mentioned in [9], *"the main challenge for the public authority is the access to relevant and up-to-date information, particularly on investment and operational costs. Absent this information – the risk of under- or overcompensation is significant"*.
- Assessment of the average market price or reference price: such average value highly depends on several parameters, such as the level of demand which is notably linked to weather conditions and to economic situation, the flexibility of demand which is currently developing, the fuel costs, the CO_2 price, the availability of power production plants, etc.

An auction-based system for finding the needed premium could be a way to respond those challenges (see the discussion in section 2.2). Average values of Feed-in-Tariffs and Price Premiums considered for the different countries covered by the study are displayed in ***Table 3*** and ***Table 4***.Regarding the 2020 RES+ scenario, it can be noted that in countries where no offshore wind is to be installed, the PP for wind is very low (because the average LCOE for onshore wind is quite close to the average market price).

[13] The LCOE represents the present value of the total cost (overnight capital cost, fuel cost, fixed and variable O&M costs, and financing costs) of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments, given an assumed utilisation, and expressed in terms of real money to remove inflation.

Table 3. *Assessment of support schemes for solar generation for the three scenarios*

	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
2013 scenario										
Percentage of PV generation sold under feed-in tariff	100%	100%	100%	88%	100%	100%	100%	100%	100%	100%
PV Feed-in tariff average value (€/MWh)	250	250	250	250	250	250	250	250	250	250
Percentage of PV generation sold under premium prices	0%	0%	0%	12%	0%	0%	0%	0%	0%	0%
PV premium average price (€/MWh)	-	-	-	107	-	-	-	-	-	-
2020 standard scenario										
Percentage of solar generation sold under feed-in tariff	30%	76%	45%	59%	34%	72%	25%	23%	44%	31%
PV Feed-in tariff average value (€/MWh)	250	250	250	250	250	250	250	250	250	250
Percentage of solar generation sold under premium prices	70%	24%	55%	41%	66%	28%	75%	77%	56%	69%
PV premium average price (€/MWh)	84	84	105	84	83	75	83	108	108	85
2020 RES+ scenario										
Percentage of solar generation sold under feed-in tariff	18%	62%	29%	44%	20%	56%	15%	13%	28%	18%
PV Feed-in tariff average value (€/MWh)	250	250	250	250	250	250	250	250	250	250
Percentage of solar generation sold under premium prices	82%	38%	71%	56%	80%	44%	85%	87%	72%	82%
PV premium average price (€/MWh)	71	73	101	71	71	68	71	102	100	72

Table 4. *Assessment of support schemes for wind generation for the three scenarios*

	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
2013 scenario										
Percentage of wind generation sold under feed-in tariff	100%	0%	100%	0%	0%	100%	0%	100%	100%	100%
Wind feed-in tariff average value (€/MWh)	94	-	82	-	-	122	-	74	81	146
Percentage of wind generation sold under premium prices	0%	100%	0%	100%	100%	0%	100%	0%	0%	0%
PV premium average price (€/MWh)	-	82	-	93	85	-	98	-	-	-
2020 standard scenario										
Percentage of wind generation sold under feed-in tariff	50%	0%	41%	0%	0%	71%	0%	83%	88%	5%
Wind feed-in tariff average value (€/MWh)	94	-	82	-	-	122	-	74	81	146
Percentage of wind generation sold under premium prices	50%	100%	59%	100%	100%	29%	100%	17%	12%	95%
Wind premium average price (€/MWh)	19	51	48	41	74	10	50	44	43	20
2020 RES+ scenario										
Percentage of wind generation sold under feed-in tariff	33%	0%	26%	0%	0%	55%	0%	70%	79%	3%
Wind feed-in tariff average value (€/MWh)	94	-	82	-	-	122	-	74	81	146
Percentage of wind generation sold under premium prices	67%	100%	74%	100%	100%	45%	100%	30%	21%	97%
Wind premium average price (€/MWh)	6	40	43	28	61	3	38	38	35	7

2.3.4 Main findings of the study

With the configuration presented in the previous section, the following trends are observed (as presented in the D4.2 report [5]).

Volumes exchanged on the day-ahead market

- RES support schemes have very little impact on the volumes exchanged on the day-ahead market: even if support schemes impact the way renewable generation is offered on the market, they hardly have an impact on the merit order curve, and, consequently, on the generation mix.
- However, there is a more significant impact of support schemes on volumes from wind and solar sources in Portugal and Spain. This is because these two countries combine the following features: repeated situations with "negative residual load" (generation from non-dispatchable sources high enough to cover the domestic load), and limited cross-border capacities.

Costs and profits

- Feed-in-Tariffs would remain a major source of revenues for solar producers at 2020, due to existing installations currently under FIT.

Market prices

- Feed-in-tariffs, in particular because of the priority dispatch usually associated to those, contribute to a growing occurrence of negative prices between 2013 and 2020[14].
- Apart from Portugal and Spain, the share of the time with negative electricity prices would increase from 0% in the 2013 and 2020 standard scenarios to 1% in the 2020 RES+ scenario. For the latter scenario, the sum of electricity price plus wind FiP would be negative in 25% of the occurrences of negative electricity prices.

Sustainability

- At the day-ahead stage, RES support schemes in general and the gradual move from FiT to PP in particular have very little impact on the environmental sustainability indicators (CO_2 emissions and share of RES), which is consistent with the tiny impact on the volumes exchanged on the day-ahead market.
- For the institutional sustainability, the expected move towards FiP is a remedy for avoiding excessive negative electricity prices. However, the problem of negative electricity prices could be reduced even further by setting the feed in premium or tariff to zero whenever the electricity price below zero (see the discussion in section 2.4.2).

[14] Negative prices may also be caused by a lack of flexibility of conventional generation units.

Cross-border market integration

- RES support schemes in general and the gradual move from FiT to PP in particular have little impact on cross-border flows, except at the borders of the Iberian Peninsula.
- RES support schemes foreseen at 2020 will cause a major increase in the congestion revenue at the borders of the Iberian Peninsula.

General conclusion of the study

RES support schemes in general, and the move from FiT to market-based schemes in particular, mainly impact investment decisions in RES capacities. In principle, they are not designed to interfere with short-term markets. Still, because short-term behaviour of RES generators is influenced by the RES support schemes granted to them, changes in RES support schemes have some impact on short-term market outcomes.

In particular, high shares of RES, if combined with low interconnectivity (insufficient cross-border interconnection capacities) may cause repeated situations with negative residual load, meaning that generation from non-dispatchable sources is higher than domestic load. RES support schemes will need to take these situations into account to avoid incentivizing RES producers to generate electricity under negative prices.

Regarding the design of price premium schemes, several parameters are of utmost importance. Within this study, we have assessed price premiums as the difference between the foreseen electricity prices (per country) and the foreseen LCOE (per technology), taking into account an acceptable profit (7%) for RES producers. Estimating the future electricity prices is challenging, since many parameters have to be taken into account: structure of the generation park, fuel costs, CO_2 price, etc. Assessing LCOE values several years in advance is also a challenge. These difficulties should be taken into account when designing premium schemes, in particular for small installations exempted from participating in competitive bidding processes (see sections 2.1.3 and 2.4). In addition, the deployment of demand response (chapter 3) will have impacts on average market prices, since load peak shaving should allow decreasing price spikes (both in magnitude and in frequency). This will have impacts on the price premium calculation.

2.4 Roadmap for the transition from Feed-in-Tariffs to market-based schemes up to 2020

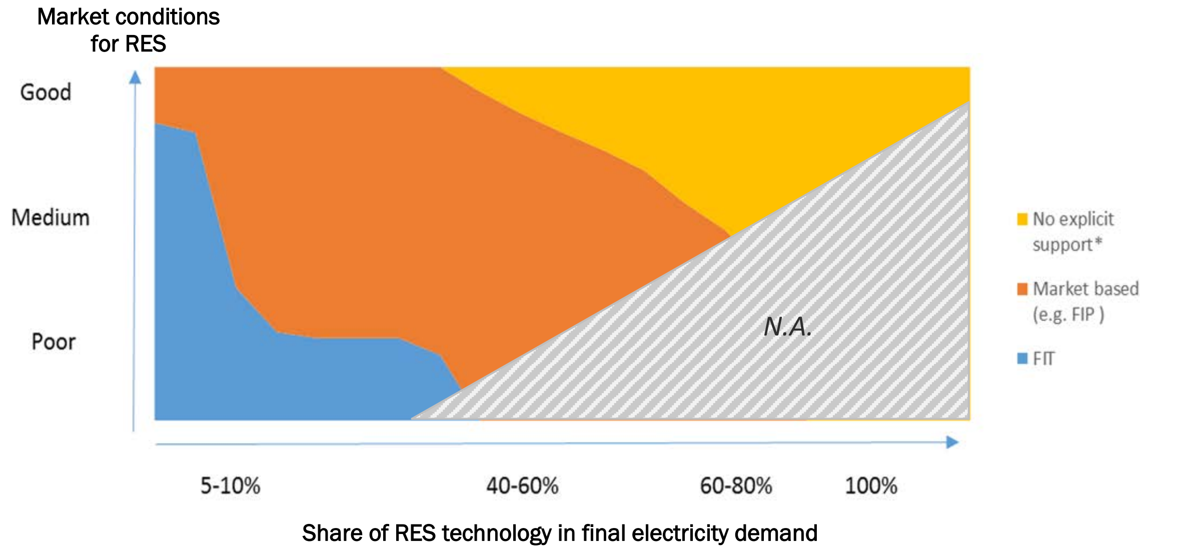
2.4.1 General roadmap – 2020 horizon and beyond

The Market4RES consortium anticipates that RES support schemes need to be adapted based on two dimensions:

- **The level of RES penetration**: the more RES are already installed, the less public support is necessary as the industry matures and integrates into market participation;
- **The market conditions**: the more the markets are fit for RES generation, the less RES capacities need financial support.

These interrelations are graphically represented in ***Figure 7***, in which the RES share is represented on the horizontal axis, and market conditions represented in a simplified manner (good, medium or poor) on the vertical axis. The numbers in the figure are only indicative.

Figure 7. *Support schemes adapted to market conditions and RES penetration*



**Explicit support is needed when other complementary markets do not function correctly and when environmental externalities are not internalized.*

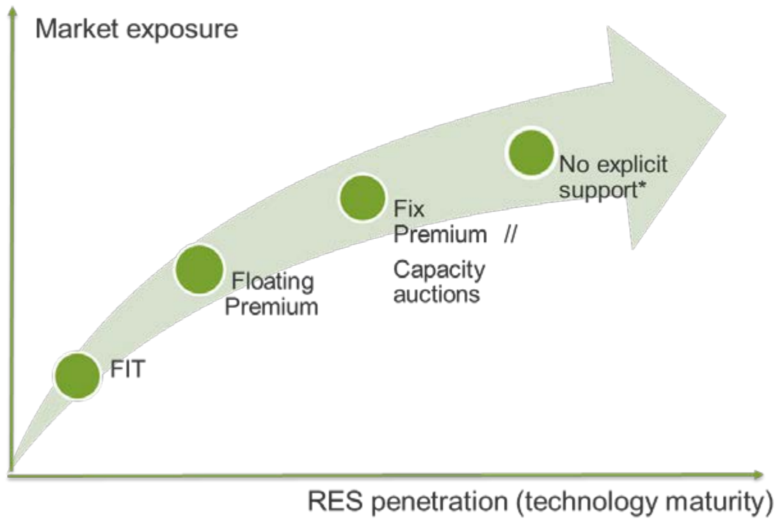
The Market4RES consortium considers that Feed-in-Tariffs are the best support mechanism in case of low RES penetration (new technologies, or recent use of technologies within a new market), or poor market conditions (or both). This was the typical situation for many countries in the EU for instance around 1980. Among the most important necessary market conditions for the sustainable growth of renewables, we should highlight:

- Existence of short-term markets (intra-day) with appropriate levels of liquidity,

- Cross-border trading in the day-ahead and intraday timeframes,
- Fair access to the balancing market for renewable energy producers and demand side management participants,
- Voltage control regulation opened to renewable energy players,
- Transparent curtailment rules and compensation schemes,
- No priority dispatch for any form of technology,
- ETS reform,
- Use of standardized methodology for regional system adequacy, avoiding support to keep system overcapacity.

The transition to market-based schemes is desirable from a certain level of RES penetration which depends on market conditions (Figure *7* indicates from 10-15% of RES penetration if market conditions are good, to 40-60% of RES penetration if market conditions are poor). Today, markets have been improved considerably in many countries. With liberalization of power markets and EU processes for harmonization and increased cross-border trades, among other things to reduce the costs of integration of renewable electricity, there are liquid day-ahead markets and emerging intraday markets in many countries. However, liquidity of intraday markets needs to improve, and there are still much to do in the reformation of balancing markets and ancillary services. Still, with the level of integration of renewable electricity and maturing of markets, we are about to enter the phase where PP will be a more adequate instrument than FiT.

Figure 8. *The roadmap from Feed-in tariffs to no explicit support for RES-E generation*



**Explicit support is needed when other complementary markets do not function correctly and when environmental externalities are not internalized.*

The overall roadmap for moving away from feed-in-tariffs is graphically represented in *Figure 8*. It will be detailed and justified in the upcoming Market4RES deliverable D6.2 "Guidelines for implementation of new market designs for renewable energy sources beyond 2020".

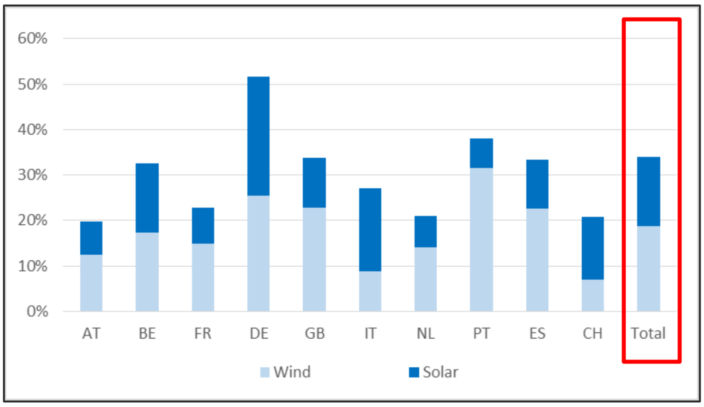
Here, we are going to focus on the possible evolution of RES support schemes within the 2020 horizon, which corresponds to left hand side in both *Figure 7* and *Figure 8*.

2.4.2 Focus on the 2020 horizon

Share of wind and solar capacities at the 2020 horizon

At 2020, the share of wind and solar capacities in the generation park should reach in total 34% within the geographical scope of 11 countries considered in the quantitative study reported in section 2.3 (19% for wind and 15% for solar). Figure *9* shows this share on a per country basis. This assumes that 2020 objectives are reached, corresponding to the 2020 standard scenario described in section 2.3.

Figure 9. *Assessment of the share of wind and solar capacities in the generation park per country, at the 2020 horizon*

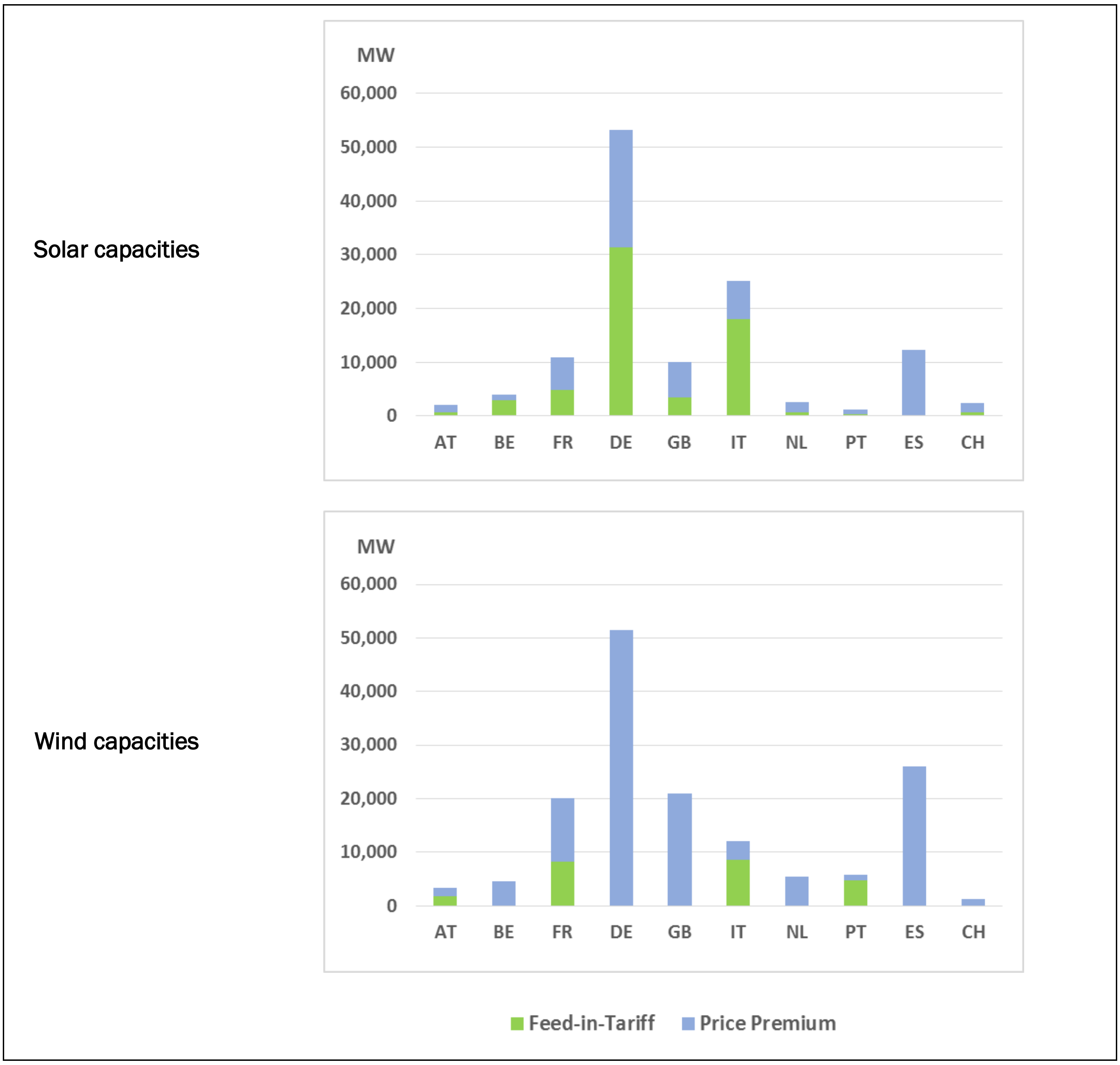


Assessment of the wind and solar capacities under market-based schemes at the 2020 horizon

The share of capacities under market- and non-market-based schemes, as assessed in the quantitative study reported in section 2.3, are represented in *Figure 10*.

Here we assume that capacities currently under FiT will remain under FiT at 2020 (no retroactive application of price premium on existing installations – except in Spain where retroactive measures have been implemented). In that case, **51% of solar capacities will still be under FiT at 2020**; and **15% of wind capacities will also be under FiT** (this again assuming that 2020 objectives are reached, corresponding to the 2020 standard scenario described in section 2.3).

Figure 10. *Assessment of wind and solar capacities under market- and non-market-based support schemes at the 2020 horizon*



Possible configuration of market-based support schemes up to 2020

Regarding the design of Feed-in-Premium schemes, there are different aspects to be considered, as described in CEER report [9]. At least four dimensions exist for configuring FIP schemes, each with several options as listed below.

Some of these dimensions have already been discussed in the present report (sections 2.1.3 and 2.2) – but not all.

- **Administrative vs. competitive process to determine the premium**:
    - The EC Guidelines on State aid for environmental protection and energy 2014-2020 [10] impose the premium to be granted from January 2017 in a competitive bidding process (tenders or auctions)[15]. There are many design options for such auctions: these are detailed below.
    - Still, the Guidelines foresee that *"with regards to small producers of renewable energy, small installations or technologies in an early stage of development can be exempted from participating in competitive bidding processes"*. This means that the premium would be set in an administrative manner[16]. Usually, the setting of the premium is based on the overall cost of RES production (depending on each technology). This has been simulated in the quantitative studies reported in section 2.3 where the levelized cost of electricity (LCOE) calculated by the International Energy Agency has been used as a reference value for assessing the overall costs (including a profit of 7%) of wind and solar production.
- **Fix vs. floating premium**:
    - Fix premium: with this option, RES producers receive a fix premium on top of market prices. This is the option that has been modelled in the quantitative analyses reported in section 2.3.
    - Floating premium: with this option, RES producers receive the difference between a reference value and a reference market price if this difference is positive. When the difference is negative, there are two options: either RES producers have to pay back this difference (which will then lead to a system similar to FiT), or the premium is set to zero. How to calculate the reference value and the reference market price are crucial elements to find the right balance for the risk sharing between RES producers and rate-payers.
    - Detailed analysis and comparative advantages of these two options will be carried out in upcoming deliverable D6.2 *"Guidelines for implementation of new market designs in Europe with high shares of RES-E penetration (post-2020)"*.
- **Caps and floors**: The risk that the premium is too low or too high can be mitigated by applying caps and floors to the total revenue. According to [9], *"one of the main challenges of this design is to set the value of the cap and the floor, especially if it is set for a long time period (15-20 years). It can also cause difficulties when applying it with auction as there are more parameters to deal with"*.
- **Payment of the premium in case of negative prices**: The EC Guidelines [10] imposes that *"measures are put in place to ensure that generators have no incentive to generate electricity under negative prices"*. Indeed a premium scheme can distort the signal given by negative prices to stop or reduce electricity production. If no premium is paid at times

[15] This corresponds to options "FIP resulting from an auction" in sections 2.1.2 and 2.2.

[16] This corresponds to options "FIP regulated" in sections 2.1.2 and 2.2.

when electricity prices are negative, this must be compensated by a slightly higher premium in general (whether it is administratively set or it is an outcome from an auction-based system).

In addition, as explained by CEER in [9], implementing FIP as support mechanism induces new costs and risks elements for RES producers when integrating into the market, such as:

- transaction costs (e.g. stock exchange registration fees, marketing staff costs);
- balancing costs (electricity is sold according to schedules and producers have to buy or sell balancing energy if they deviate from schedule); and
- forecasting and scheduling costs – they can be substantial especially for intermittent generation where producers need to forecast resource availability (e.g. meteorology software or forecast) and adjust the schedules accordingly. In many cases forecasts are accurate enough only quite close to real time (few hours ahead).

For new entrants these costs can be taken into account in the reference support value, set either through an administrative or competitive procedure:

- In a competitive procedure, the compensation of these costs can be integrated in the total level of remuneration asked by the bidders.
- In an administrative procedure, it has to be estimated by public authorities, which can be a challenge given the lack of experience on this issue. More generally, the level of the "direct marketing" premium will be a trade-off between the will to develop this activity and the costs of the scheme.

Competitive bidding procedures (auctions, or tenders) are increasingly used across the globe as an allocation mechanism for deploying RES. With a view on Europe and solar PV in particular the experience is rather limited today. However, the new State Aid regime incentivizes Member States to use tenders: after a transitional phase in 2016, all new PV plants above 1 MW will indeed have to compete for support in a bidding process from 1st of January 2017 (see section 2.1.3).

Several countries already anticipated this shift. As far as these recent experiences can tell, design parameters play a crucial role and practices currently vary substantially across the different EU countries. With a view on the outcomes of the assessment of RES support schemes in Section 2.2 based on [8] and [3] that favour tenders (categorized as auctions in this report) it is recommended to conduct research upon the design of such auctions. Although in-depths analyses regarding this topic are outside the scope of this report, the project suggests to take a holistic perspective in respect to the sequence of auctions and related topics, a non-exhaustive list of relevant topics is provided below:

- **"Before the auction": Deploying volumes and ensuring visibility for investors**
  - Scope of the auction (national, regional, or European);
  - Technology neutral vs. specific;
  - Capacity and frequency of auctions;

    - Size of systems included in an auction;
    - Pre-qualification criteria;
- **"During the auction": Applicant friendly design parameters for cost-effective auctions**
    - Price settlement;
- **"After the auction": Ensuring project fulfilment**
    - Time to deliver;
    - Transparency on bids selected;
    - Liabilities and penalties in case of delay or non-fulfilment;
    - Secondary market and resubmission of unsuccessful bids.

Next to the existing and extensive literature that already exists on auctions (see for instance [15], [16] and [17]), the following highlights additional fundamental issues that should be kept in mind when designing tendering /auction schemes:

- **It is important for applicants to reduce development costs by reducing the variance of tendering schemes across Europe.** In theory, European-wide tenders would ensure uniformity in the treatment of bidders and promote the most attractive projects on a European scale. In the short to medium-term, we however consider that for practical reasons and local acceptance issues the direct control by Member States on the tendering process is a more realistic option. Harmonization between Member States' tendering systems should however be pursued in order to facilitate access for a larger number of participants. Similar process designs, comparable participation requirements, streamlined and harmonized administrative procedures as well as a stepwise opening to transnational bidding would all help to promote a real international competition. Such commonalities would contribute to prepare a long-run convergence of cross-border or even EU-wide tenders.
- Given the transaction costs associated with a tendering process, it is important to maintain the possibility for **smaller projects below 1 MW to be developed via other types of mechanisms.**
- Finally, in case the market is not considered liquid enough, the **pre-qualification criteria should be adapted or extended** in order to reflect other objectives such as technical or environmental quality.
- Once the preparatory phase is completed, project developers will have to compete. **Transparency** and **simplicity** should be the main guiding principles during the selection process.

3 DEMAND PARTICIPATION IN SHORT-TERM MARKETS

In this chapter, we provide a comprehensive vision of demand flexibility in Europe, which is consensually seen as an important resource for achieving a low-carbon, efficient and affordable electricity system. This vision is based on the work carried out by the Market4RES consortium during the last two years. It encompasses a review of existing demand response mechanisms, a qualitative assessment of these and a quantitative analysis of demand flexibility deployment. This work allows the Market4RES consortium to provide some recommendations about the further involvement of demand response in short-term markets in Europe.

3.1 General framework

3.1.1 Rationale for demand flexibility development

As stated in Market4RES report D2.1 [2], *"demand participation in markets could result in a decrease in system operation costs, an increase in the level of integration renewable generation, thus paving the way for higher RES-E penetration levels, and an increase in the level of competition, thus contributing to a reduction in the level of prices, among other benefits"*.

Demand participation is indeed needed because of the "electricity trilemma" described in [18]:

- *"Electricity cannot yet be stored economically, so the supply of and demand for electricity must be maintained in balance in real time.*
- *Grid conditions can change significantly from day-to-day, hour-to-hour, and even within seconds. Demand levels also can change quite rapidly and unexpectedly causing mismatches in supply and demand, which can threaten the integrity of the grid over very large areas within seconds.*
- *The electric system is highly capital-intensive, and generation and transmission system investments have long lead times and multi-decade economic lifetimes."*

Still, the need for demand response has not always been so urgent. Nowadays - and even more importantly within the future electricity system integrating higher shares of variable renewables, demand response (as well as other flexibility means) is increasingly needed, because the generation fleet will decreasingly be able to follow the load unless mechanisms are in place to ensure a considerable over-capacity. Rather, the load will perhaps more and more follow the non-dispatchable generation by being decreased or shed during low-production hours and possibly increased during high-production hours.

Demand response shall therefore be one of the central topics to be addressed by the European Commission in its legislative proposals to redesign the electricity market, expected in the second half of 2016. In its public consultation document [19], the EC indeed states that *"successfully integrating renewables' electricity generation into the system requires flexible markets encompassing a broader range of players, both on the supply and demand side"* and that *"the integration of the internal market should not stop on the wholesale level. To realise the full* *potential of the European internal energy market, the retail part of the electricity market has to offer consumers – households, businesses and industry – the possibility of active and beneficial participation in the European Union's energy transition. This has to be one of the goals of the new market design and requires a fundamental change in the role of the consumer on the electricity market".*

3.1.2 Review of existing market design options for demand participation in short-term markets

In the Market4RES report D3.2 addressing the developments affecting the design of short-term markets [3], different approaches have been considered to make demand flexibility (or demand-side response – DSR) able to be valued efficiently in short term energy markets.

Consumers response to prices can be valued either implicitly through the contract with their supplier[17], or explicitly through their own participation in the market possibly through an aggregator that bids on their behalf.

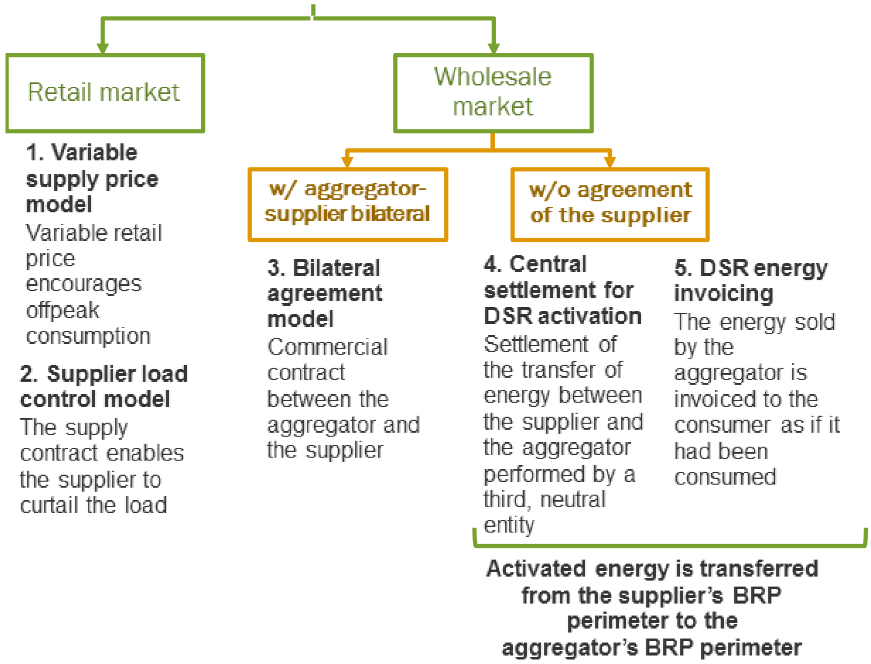
The simplest but still important mechanism to promote DSR is to expose consumers to electricity prices through their contract with their supplier, which requires metering of actual consumption. This can be applied for day-ahead market prices but also for shorter time horizons. This is illustrated by 1 in ***Figure 11***.

However, if the supplier shall be able to utilize the demand side flexibility for bidding into real-time balancing markets, it must also be permitted to curtail the load. For this, more advanced control equipment must be in place. This is illustrated by 2 in ***Figure 11***.

Consumers' flexibility may also be operated by so-called aggregators, which can control the possible curtailment of the load on their behalf. The corresponding flexibility can be sold to the consumer's supplier, which then can bid it into the market, cf. 3 in ***Figure 11***, or the aggregator can participate directly into balancing markets, cf. 4 and 5 in ***Figure 11***. See [3] for further details between the explicit demand response options considered.

[17] Or retailer: these two terms are considered as synonymous in this report.

Figure 11. *Classification of design options considered for the participation of demand in energy markets*



3.1.3 Development of demand response in Europe

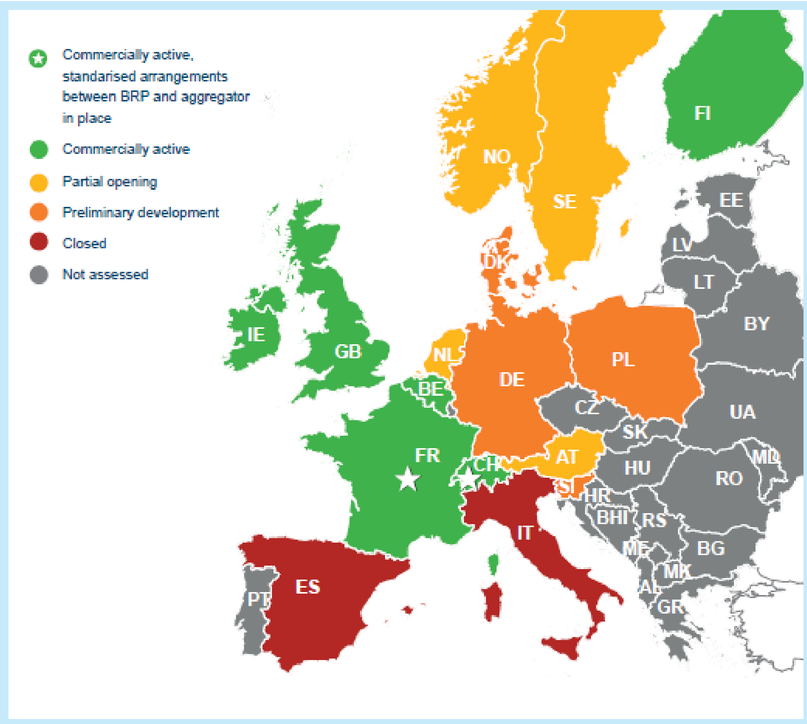
Implicit demand response from big, industrial consumers has been developed for long in most European countries. In some others, residential consumers have also been an important way of implicit DSR development like in France for instance, where electricity heating has been promoted in the same time than implicit residential DSR.

What is really new, is the development of explicit demand response thanks to the revolution in data technologies which implies a lower cost for smart meters. With the new affordable technologies in smart metering, DSR operators can now develop offers for small consumers or small industries and be able to value it explicitly on the markets. This new liberty creates competition between suppliers and DSR operators on the demand response market. This new competition will develop the offers for the benefit of the electricity system. Moreover, the development of smart metering and of new index will develop the opportunities for DSR design for the suppliers.

Many research and demonstration projects have been or are being carried out in Europe to assess the potential and test the functioning of new types of residential demand response: EcoGrid EU and EcoGrid 2.0[18], Grid4EU with the Nice Grid demonstration[19], Address[20], Advanced[21], Linear[22] projects can be quoted as examples[23].

At the same time, commercial development of residential demand response has started in a limited number of countries, as shown by ***Figure 12***.

Figure 12. *Map of explicit demand response development in Europe Today*



Source: SEDC [18]

3.1.4 Barriers to the participation of demand in short-term markets

Demand Side Management (DSM) participation in markets could result in a decrease in system operation costs, and facilitate the integration of renewable generation, thus paving the way for higher RES-E penetration levels, and in an increase in the level of competition, thus contributing to a reduction in the level of prices, among other benefits.

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18 See http://www.eu-ecogrid.net/.
19 See http://www.grid4eu.eu/ and http://www.nicegrid.fr/.
20 See http://www.addressfp7.org/.
21 See http://www.advancedfp7.eu/.
22 See http://www.linear-smartgrid.be/en.
23 A broader list of research and innovation projects related to demand response can be found at http://www.gridinnovation-on-line.eu/.

However, in order to realize these potential benefits, some barriers, or obstacles, to the deployment of cost-efficient DSM solutions need to be overcome:

1. **Technological aspects of service provision**, related to the need to have the adequate equipment and communication protocols in place to provide such a service;
2. **Economic aspects of service provision**, related to the need to make DSM profitable for all the parties involved in the implementation of these solutions;
3. **Operational aspects related to the deployment of DSM solutions**, which are related to the difficulties for carrying out their function in the electricity system that any party may face due to the deployment of the DSM service.
4. **Control issues.** Explicit DSR development implies that a neutral entity realizes the control of DSR to rule the competition relation between the supplier and the DSR operator from their client: the consumer. These control issues open huge technical challenges on metering the consumption and determining the DSR volumes.
5. **Legal barriers.** The contract between the supplier and the consumer could easily be used by suppliers to forbid others future contracts between consumers and DSR operators. The responsibilities have to be clearly defined in the law to allow to all parties a fair competition.

In the following we will discuss some of these barriers more in detail.

Technological barriers

For the participation of demand in short-term markets, some minimal conditions need to be met:

- **Specific metering** needs to be developed. Index metering is already a good technological answer for many implicit DSR. Nevertheless, smart metering needs to be in place to allow the development of explicit DSR.
- **Communication equipment** will also be needed. The type of it depends on the DSM scheme implemented. In those cases where simple schemes, such as feedback (FB), are deployed, needs are minimum (when FB is used as a DSM measure, the participation of the demand side in markets is not direct, but indirect through the modification of the amount of load needed to be contracted by suppliers). However, if, for instance, direct load control is applied, advanced communication infrastructure is required.
- The **standardization** of technological solutions applied is also necessary to ease competition among DSM operators.

Deploying the appropriate metering and communication equipment is central to ease DSM solutions for the participation of consumers in very short-term markets, namely balancing and regulation ones. This has to do with the fact that the quickness of the response needed from consumers to changes in system conditions is only possible, if this response is fully automated, which, among other things requires the use of bi-directional communication and smart appliances.

Economic barriers

Economically speaking, one first prerequisite for the deployment of DSM services is that it is efficient from a net social benefit point of view, i.e. extra revenues, or benefits, resulting from DSM are larger than implementation costs. According to some analyses performed at European level, [[20],[21]], most DSM solutions cannot be expected to render large enough benefits to justify implementation costs. Making them profitable would require un-tapping the undiscovered potential of DSM through the deployment of highly advanced solutions; implementing very modest solutions whose implementation cost is minimal, or reducing significantly the investment costs of required equipment.

Apart from this, regulation in place must allow benefits from DSM to be distributed among parties in the system, so that all involved relevant parties find it profitable to facilitate the implementation of these solutions. Torriti et al. [22] points out, that main reasons for the slow progress of the implementation of DR policies in Europe are related to the economic factors such as the lack of knowledge about the energy saving potential of these measures, the computation of very high estimates of the cost of DR technologies and the associated infrastructures, and the fact that regulation developed with the liberalization of the energy sector has resulted in economic counterincentives for main relevant parties to facilitate the integration of DSM technologies or use them, since this would negatively affect their profits, see [22]. This concerns main groups of stakeholders:

- **Consumers:** Achieving the involvement of consumers may critically depend on the economic benefits they obtain from DSM. Increasing consumer benefits requires the computation of efficient, cost-reflective energy prices in day-ahead wholesale markets and network tariffs (both transmission and distribution ones), which should be updated periodically after long periods of time during which they remain fixed, and which may condition investment decisions by consumers together with generation capacity charges. The lack of cost reflectivity in long and short term charges and prices faced by consumers has traditionally limited the profitability that consumers can obtain from managing their load according to system needs. Moreover, the complexity of managing its own consumption in such a situation implies that the consumer will contract with an expert - the DSR operator - to furnish this service.
- Analogously to consumers, **aggregators** and **retailers** need cost-reflective energy prices in markets to be able to draw some benefits from the management of the load of their consumers. Normally, energy prices are computed according to the marginal cost principle in wholesale markets, but not in retail ones (retail prices do not include any time differentiation in many countries). The lack of efficient energy prices may discourage consumers to engage with service providers, or retailers, in DSM schemes for the organization of the electricity supply.
- **Network operators**' benefits from DSM depend on the regulation affecting the remuneration they perceive. Thus, remuneration schemes where there is a pass-through of network investment costs do not encourage operators to facilitate the application of DSM measures, while those where reduction in network investment costs result in an

increase in operators' revenues, like revenue cap schemes, tend to provide the appropriate incentives to operators. Network operators' operation costs will probably increase with DSM, but this could be taken into account in remuneration schemes. Network operators do not participate in markets, but may condition the installation of flexible demand equipment by consumers in order for the latter to be able to participate.

Besides those economic aspects that are specific to a certain group of agents, or party, there is the general need to avoid limiting more than needed the direct or indirect participation of consumers in markets through minimum-size requirements that are too restrictive; high transaction costs; or other constraints like the need to bid in markets jointly for a block of hours.

Other relevant aspect is the need to have in place the appropriate equipment and regulation to monitor the provision of the DSM service. An adequate mechanism should be put in place to determine the baseline level of load by consumers so as to determine the level of load changes achieved through DSM. This is necessary both to measure the compliance with DSM commitments acquired by consumers or aggregators and for billing purposes and has traditionally not been adequately treated in most systems. This can be considered an obstacle to the participation of demand in all types of markets, long, short, and very short term ones.

Another relevant aspect that needs to be cared about is the design of contracts affecting all parties in the system. Too strict, inflexible contracts, would not allow parties to benefit from the flexibility that active demand could provide them with.

Operation barriers

Operation aspects that have traditionally negatively affected the activation of demand concern a multiplicity of factors ranging:

- from the lack of predictability of the level of demand managed by retailers or balance responsible parties (BRPs), or that managed by TSOs within a control area, which may encourage them not to contract flexibility provided by demands or facilitate demand activation;
- to network congestion and other active technical constraints that may result from changes in the load of consumers in an area;
- going through concerns raised among consumers by the lack of an adequate level of confidentiality in the management of sensitive information about their demand profile; or requirements on access to data by rival entities, and the format of information exchanged among these entities, in order to facilitate competition among them;
- or existing uncertainties on the availability of DSM services when entities like TSOs, DSOs, or BRP need them; lack of knowledge by aggregators and service providers about the location of their consumers in the grid; uncertainty about the level of the rebound effect, or increase/resp. decrease in the consumption following a decrease/resp. increase prompted by DSM.

The existing uncertainty about the dynamics of the activation of demand may play a critical role when contracting regulation reserves (mainly tertiary ones) from consumers or aggregators. This could deter operators from contracting it from demand.

3.2 Qualitative assessment of market design options for demand participation in short-term markets

In the Market4RES report D3.2 [3], the different approaches presented in the previous section have been qualitatively assessed against a range of criteria, as presented in ***Table 5*** below.

Table 5. *Summary of the assessment of options for organizing demand response in the short term*

		Implicit options		Explicit options		
		Variable supply price	Supplier load control	Bilateral agreement	Central settlement	DSR energy invoicing
Efficiency	Marginal cost reflectivity	Fair	Good	Fair	Good	Very good
	Cost causality	Good	Very good	Fair	Very good	Very good
	Liquidity	Poor	Poor	Very good	Very good	Very good
Implementability	Feasibility	Good	Good	Good	Poor	Poor
	Compatibility & simplicity	Very good	Very good	Fair	Poor	Poor
	Implementation costs	Good	Good	Good	Poor	Poor
	Level of use of public funds	Very good	Very good	Very good	Good	Very good
	Scalability	Very good	Fair	Very good	Very good	Fair
Fairness	Competition	Poor	Poor	Fair	Very good	Very good
	Confidentiality	Very good	Very good	Poor	Very good	Good
	Allocation of implementation costs	Good	Good	Very good	Fair	Good
	Level playing field for DSR	Fair	Fair	Fair	Very good	Very good

The report D3.2 [3] concludes: *"Regarding the participation of demand in short term markets, all options available, both implicit and explicit schemes, should be allowed to provide consumers with large flexibility. Implicit schemes are the simplest ones and reasonably efficient. However, under these schemes, agents cannot compete to access DSR resources. Then, the implementation of independent load aggregators should also be considered an option. The transfer of funds between aggregators and suppliers should be set by an independent entity for the treatment to both of them to be fair and in order to promote efficiency in market functioning."*

This conclusion is fully in line with the following statement from the smart energy demand coalition SEDC [18]: *"It is important to note that neither form of Demand Response is a replacement for the other. Many customers participate in Explicit Demand Response through an aggregator, and at the same time, they also participate in an Implicit Demand Response programme, through more or less dynamic tariffs. The requirements and benefits of each are different and build on each* *other. The two are activated at different times and serve different purposes within the markets. They are also valued differently. While consumers will typically receive a lower bill by participating in a dynamic pricing programme, they will receive a direct payment for participating in an Explicit Demand Response programme."*

3.3 Quantitative analysis of the deployment of demand flexibility on short-term market outcomes

Here, we refer to a Market4RES study carried out with the OPTIMATE prototype tool. The methodology implemented and the specifications of the study are described in the Market4RES reports D4.1 [4], and the detailed results are presented in the Market4RES reports D4.3 [6].

The purpose of the study is to provide a quantitative evaluation of the impacts of demand flexibility deployment, irrespective of the market design leading to such deployment.

In this study demand flexibility is modelled as load shedding voluntary done by consumers to arbitrate between high- and low-price hours. This supposes that consumers are exposed to hourly wholesale market prices. We do not discuss here the different possible market designs leading to such situation (as described in sections 3.1.2 and 3.2).

3.3.1 Specifications of the study

Three scenarios are considered within the study: there have already been described in section 2.3.2 since all OPTIMATE studies have been carried out using the same scenarios as inputs:

- The **2013 scenario**, also called **reference scenario,** mimics the current situation of the power system.
- The **2020 standard scenario** mimics the situation of the power system, which can reasonably be expected at 2020.
- The alternative **2020 RES+ scenario** is derived from the 2020 standard scenario. Within this scenario, RES installed capacities result from doubling the increase in RES installed capacities from 2013 to 2020; in addition, these new RES capacities replace some thermal capacities, the latter being both more flexible, and more costly through an increased CO_2 cost (see [4] for all details).

All scenarios are based on a geographical scope covering 11 countries as depicted in ***Figure 6***, page 28. For each of these scenarios, five cases have been considered as presented in ***Table 6***.

Table 6. *Combinations of scenarios and demand flexibility variants*

Studies	Scenarios	Demand flexibility	Demand shift
Default cases	2013	None	-
	2020 standard	None	-
	2020 RES+	None	-
Study on demand flexibility	2013	Mid	None
	2013	Mid	Full
	2013	High	None
	2013	High	Full
	2020 standard	Mid	None
	2020 standard	Mid	Full
	2020 standard	High	None
	2020 standard	High	Full
	2020 RES+	Mid	None
	2020 RES+	Mid	Full
	2020 RES+	High	None
	2020 RES+	High	Full

First, a default case in which no demand flexibility is applied: corresponding short-term market outcomes represent therefore default values against which the impacts of different variants of demand flexibility deployment can be assessed.

Second, two variants have been adopted to model the deployment of demand flexibility:

- **Mid variant**: in this case, **5%** of the load is shed when prices reach the **95th centile** (in other words, during the 5% of the hours covered by the simulation with the highest prices);
- **High variant**: in this case, **10%** of the load is shed when prices reach the **90th centile** (in other words, during the 10% of the hours covered by the simulation with the highest prices).

Third, demand shift can occur when load is shed: in principle, a certain proportion of the load which is shed during high-price hours should be shifted to low-price hours. This proportion being hardly assessable, it has been decided for the study to consider two extreme situations:

- **No demand shift** (default option in OPTIMATE). This means that if peak load is shed, there is no compensation by an increase in electricity consumption during off-peak hours.
- **Full demand shift**: in this case, 100% of the peak load that is shed is compensated by an increase in consumption during off-peak hours possibly <u>before</u> and <u>after</u> the load shedding.

3.3.2 Main findings of the study

With the configuration presented in the previous section, the following trends are observed (as presented in the D4.3 report [6]).

Generation mix

- Demand flexibility has an impact mainly on the production coming from fossil fuels. Both production from gas and coal units decrease.
- In all countries, production from gas is significantly impacted by demand flexibility: this was expected since gas is one of the main peak generation means. Still, in countries with the highest amounts of generation from gas (Italy, Great Britain, Netherlands and Germany), the relative impact of demand flexibility is limited, since in those countries gas is not only used during peak hours but is actually a semi-base means.
- In countries with the highest coal generation (Germany, Great Britain, Italy and Spain), demand flexibility has little impact on coal production. It is in France and in Portugal that the deployment of demand flexibility impacts the most the generation from coal.
- If demand shift occurs, the production from gas units is less impacted compared to the production without demand shift. The same behaviour occurs for the coal production.
- The impacts of load flexibility and demand shift on the generation mix of each country is closely linked with cross-border flows.

Costs and profits

- Demand flexibility clearly impacts the thermal generation costs, since in general demand shedding will be applied when peak units are running (mainly based on fossil fuels). This impact increases with the development of demand response (from mid to high development) and with more RES penetration (from scenarios 2013 to 2020 standard and RES+). Within our estimations, annual electricity generation costs could be decreased by 458 to 1,143 million of euros in the reference scenario, 934 to 2,071 million of euros in the 2020 context (2020 standard scenario), and 813 to 2,161 million of euros if 2020 objectives are surpassed (2020 RES+ scenario).
- In terms of revenues, thermal producers are obviously impacted. First, as all other producers, their revenues are impacted by the decrease market prices due to load shedding. Second, the annual volume of energy generated by thermal power plants also decreases with demand flexibility: this is why the impact on thermal producers in terms of annual revenues is higher than those of RES producers (whose production remains stable).
- Still, the revenues of RES producers are also impacted by the price shaving due to demand flexibility. Wind and solar producers are impacted in different ways due to the different production profiles combined with the load shedding profile, in particular for scenarios with high RES penetration.
- Finally, the consumer surplus also decreases with increasing deployment of demand flexibility. This is not an obvious impact since the deployment flexibility has logically two

opposite impacts on consumer surplus: on the one hand, the decrease in market prices caused by load shedding should have a positive impact on the consumer surplus; on the other hand, the decrease in consumption will have a direct negative impact on consumer surplus[24]. It appears that the latter impact is greater than the former.

- If demand shift applies:
  - Compared to demand flexibility without demand shift, the annual thermal generation costs decrease to a lower extent. This is consistent with what was expected, since the total production with demand shift is higher than without demand shift.
  - The annual thermal producer revenues follow the same trend, for the same reason: with demand shift, thermal generators produce more energy than without, thus earning higher revenues (volume effect). By contrast, in terms of average revenues per MWh generated for thermal producers, the trend is opposite: demand shift affects negatively their average revenue per MWh generated. This can be explained by the fact that demand shift is positioned during low price hours; therefore, with demand shift, thermal producers have to sell more energy during these low price hours than without demand shift; the impact on prices of demand shift is not high enough to compensate this effect.

Market prices

- Demand flexibility has a significant impact on average market prices: within all cases, this impact lies between -1% and -4%.
- In addition, there are significant differences between countries. For most of the countries studied, the impact of demand flexibility on the market price lies between -1% and -5%. Countries facing very high price peaks (within our modelling, Portugal is in this situation within the 2013 scenario) are much impacted since price peaks are significantly shaved.
- Demand flexibility has a major impact on the average daily spread (difference between the maximum price of the day within a given market area and the minimum price of the same day and market) with significant differences between the three scenarios and the market areas. Again, in countries facing high price peaks, the impact on the daily spread is most significant.
- Demand flexibility with demand shift, compared to demand flexibility without demand shift, has a slightly lower impact on the average market prices. This was expected since demand shift increases the prices during low-price hours. For the very same reason, demand shift allows decreasing even more the average daily spread, leading to a very significant impact.

[24] However, this effect of demand response will only exist in partial models that do not take into account the impact on welfare obtained in other markets. For a discussion, see Wolfgang, O. and Doorman, G. (2010), "Evaluating demand side measures in simulation models for the power market", Electric Power Systems Research 81, 790-797.

Thanks to load shedding combined with demand shift, on average, the residual load[25] is flatter, and so are the average prices.

Sustainability

- Demand flexibility has an important impact on CO_2 emissions compared to the proportion of load shed. Within our hypotheses, between 10 and 39 million of tons (Mt) of CO_2 would be saved each year, representing 0.7% to 3.7% of the total CO_2 emissions from power generation. The distribution per country of these savings depends on the impacts on fossil fuel generation which has been previously described.
- The existence of demand shift would allow lower savings, from 5 to 29 Mt depending on the different cases studied.

Cross-border market integration

- Demand flexibility causes a general increase of cross-border flows, and the interconnection utilization rate increases. This means that cross-border interconnections are used closer to their full capacity (in the relevant market direction).
- The average price differential magnitude drops, in particular within the 2013 scenario. This is related to the previous point, but also to the decrease in the average prices within each market as previously described: price peaks being shaved, price differentials between countries are also reduced, on average.
- Still, the occurrence of price convergence significantly decreases. This means that even if on average, prices are closer to each other, they are less often equal. This is in fact consistent with the increase of the interconnection utilisation rate: when interconnections are fully used, it means that prices are not necessarily equalized.
- The congestion revenue depends on the amount on cross-border flows, and on the price differentials. The increase in cross-border flows being low compared to the decrease in average price differential, the impact of demand flexibility on congestion revenue is negative. Within our estimates, the decrease in the total congestion revenue would lie between 0.2% and 6.8% depending on the cases and the scenarios.
- On individual borders, the impacts of load shedding possibly combined with demand shift vary a lot. On borders with a very high use of interconnection capacities always in the same direction, the changes in market prices on each side of the borders caused by demand flexibility are not high enough to change the general patterns of the flows.
- In countries with high interconnection capacities, load shedding and demand shifts are partially compensated by domestic production, the rest being addressed by an adaption of cross-border flows. By contrast, within "electric peninsulas" (with lower import/export

[25] The residual load is the difference between load and non-dispatchable generation such as wind, solar and must-run.

capacities) load shedding and demand shifts must be compensated mainly with an adaptation of the domestic production.

General conclusion of the study

In order to achieve European Union energy policy and decarbonisation targets, the study has demonstrated that demand flexibility can be a key component. Quantifying the real benefits of demand flexibility is however very challenging and complex for many reasons. We have not estimated the probable or possible demand response that can be realized. However, we have studied the impact of a given demand flexibility, including reduced demand at high prices and load shifts from periods of high prices to periods of lower prices.

3.3.3 Comparison with other studies

In 2008 a report was published by Capgemini in collaboration with Vaasaett and Enerdata: "Demand Response: a decisive breakthrough for Europe - How Europe could save Gigawatts, Billions of Euros and Millions of tons of CO_2" [23]. This report is a well-known reference which compiles results from various studies about demand response and provides a quantitative assessment of the impacts of demand response deployment at the 2020 horizon – seen from the 2008 viewpoint.

It is very interesting to compare this viewpoint from 2008 to the assumptions and findings from the Market4RES study carried out in 2015-2016 and presented in the D4.3 report [6]. ***Table 7*** below highlights the most interesting aspects in this comparison.

Table 7. *Comparison of assumptions and findings of two studies assessing the impacts of demand flexibility deployment*

Capgemini et al., 2008	Market4RES 2015-2016
Assumptions	
Scope: EU-15 (AT, BE, ***DK***, ***FI***, FR, DE, ***GR***, ***IE***, IT, LU, NL, PT, ES, ***SE***, ***UK***)	Scope: 11 countries as depicted in ***Figure 6*** (AT, BE, ***CH***, FR, DE, ***GB***, IT, LU, NL, PT, ES)
"The peak demand is expected to grow at least as fast as the electricity consumption (an increase of about 1.8% per year for EU-27 by 2020)"	According to ENTSO-E forecast (scenario B in SO&AF 2014 report [14]), the growth in peak demand is not that significant: from 526 GW in 2014 to 555 GW in 2020, meaning an average growth of 0.9%.
"Currently CO_2 emissions certificates are relatively cheap, and have insufficient financial impact on the utilities. From 2013 to 2020 however the electricity sector will have to auction 100% of its needed allowances, increasing costs for both the utilities and the end customer."	The CO_2 price considered in the Market4RES study (2013 scenario) is still low, at 4.38 €/ton (EEX price). For 2020 a price of 10€/ton has been considered (EC source).
"DR measures based upon two alternative future scenarios: The first is a Moderate scenario, which aims to map the outcome of DR if current market trends continue. The second scenario is substantially more Dynamic." Baseline, Moderate and Dynamic scenarios are based on **bottom-up, country-by-country assumptions** about the number of households, the current penetration of electrical equipment, the status of implementation of smart meters, the proportion of consumers participating in demand-response programs, etc.	In the Market4RES study, Default, MidFlex and HighFlex cases are based upon **top-down, global load shedding capability**: 0% for the Default case, 5% of load shedding capability during the 5% of hours with the highest prices for the MidFlex case, and 10% of load shedding capability during the 10% of hours with the highest prices for the HighFlex case. Two extreme cases considered: one with no demand shift, meaning that peak shaving leads to 100% of energy savings; the other with full demand shift, meaning that peak shaving leads to 0% of energy savings.
Indicators considered	
"The potential of DR within the European energy market for residential and commercial consumers [...] includes savings derived from Direct Demand Response programs and an increased use of energy saving equipment [...] (low energy lamps, energy saving refrigerators...)"	In the Market4RES study only direct demand response is considered. The use of energy saving equipment is not taken into account.
"For savings made through a decrease in current energy use the current price of electricity in each country the potential reduction of energy was translated into potential financial savings."	In the Market4RES study financial savings are calculated with the electricity prices at 2020 as calculated by the OPTIMATE simulator, based on assumptions on the power system at 2020.

"Additional economical savings are made by avoiding an increase in energy consumption and especially use of peak capacity, which leads to less need for new plants and infrastructure aimed at covering peak load. To calculate this, two assumptions were made: The first was that the price of 1 GW of new production capacity would cost 400 million Euros on average [...]; The second assumption dealt with avoided investment in transmission and distribution infrastructure. This assumed a one to one saving: one euro saved in GW would equal one euro saved in transmission or distribution costs, a relatively conservative estimate."	Such additional savings, not linked with the short-term electricity markets, have not been taken into account in the Market4RES study.
"In order to calculate CO_2 savings it was assumed that the avoided construction of generation capacity would be mainly gas plants, corresponding to an average value of 425g CO_2 per kWh from a combined cycle gas turbine plant, plus 15% difference between demand and gross generation, leading to an average value for reduced emissions of 500g CO_2 per kWh of saved demand in Europe."	In the Market4RES study CO_2 savings were calculated by OPTIMATE. They result not only from a decrease in gas-based production but also in coal-based production (> 1 kg of CO_2 per kWh).
Results	
• **Energy savings**: 59 TWh (Moderate scenario) to 202 TWh (Dynamic scenario) • **CO_2 emissions reduction**: 30 Mt (Moderate scenario) to 100 Mt (Dynamic scenario) • **Peak generation capacity avoided**: 28 GW (Moderate scenario) to 72 GW (Dynamic scenario) • **Avoided investments**: € 20 billion (Moderate scenario) to € 50 billion (Dynamic scenario) • **Annual savings in electricity bills for customers**: €25bn (Dynamic scenario)	In the Market4RES study, for the 2020 standard scenario: • **Energy savings**: 16 TWh (MidFlex case) to 39 TWh (HighFlex case) - assuming no energy shift when load is shed • **CO_2 emissions reduction**: 8 Mt (MidFlex case with energy shift) to 39 Mt (HighFlex case with no energy shift) • **Annual savings in generation costs**: 627 M€ (MidFlex case with energy shift) to 2,071 M€ (HighFlex case with no energy shift)

This comparison highlights the sensitivity of the potential impacts of demand flexibility to initial assumptions and scope. Also, it shows that for the assessment of demand response benefits made in 2008, the general trend towards falling electricity prices (due to the so-called merit-order effect, as explained in Market4RES reports D2.1 [2] and D2.3 [24]) could not be anticipated. This decrease in average electricity prices has an obvious negative impact on the potential benefits of demand flexibility deployment.

Other studies have been carried out to assess the benefits of demand response: a non-exhaustive list of publications can be found in the reference section. Some of these studies address a limited geographic scope (France in [25], UK in [26], Northern European countries in [27], PJM in [28]). Some have a wider scope but do not propose a global quantification of the financial benefits of demand response (for example [29], [30], [31]). Others, as [32], provide a more theoretical approach.

3.4 Conditions for the deployment of demand participation in short-term markets

As previously stated (section 3.1.1), demand response is increasingly needed to compensate the low flexibility of non-dispatchable, variable renewable sources. We have also explained (section 3.2) that regarding the participation of demand in short term markets, all options available, both implicit and explicit schemes, should be allowed to provide consumers with large flexibility. Finally we have quantified the benefits of demand participation in day-ahead markets within different scenarios and hypotheses (section 3.3).

Still, several questions remain unanswered at this stage, and would deserve further analysis. We propose here some routes to investigate further in order to allow a concrete and efficient deployment of demand response.

For demand response to develop at large-scale, we consider that the following conditions should all be met:

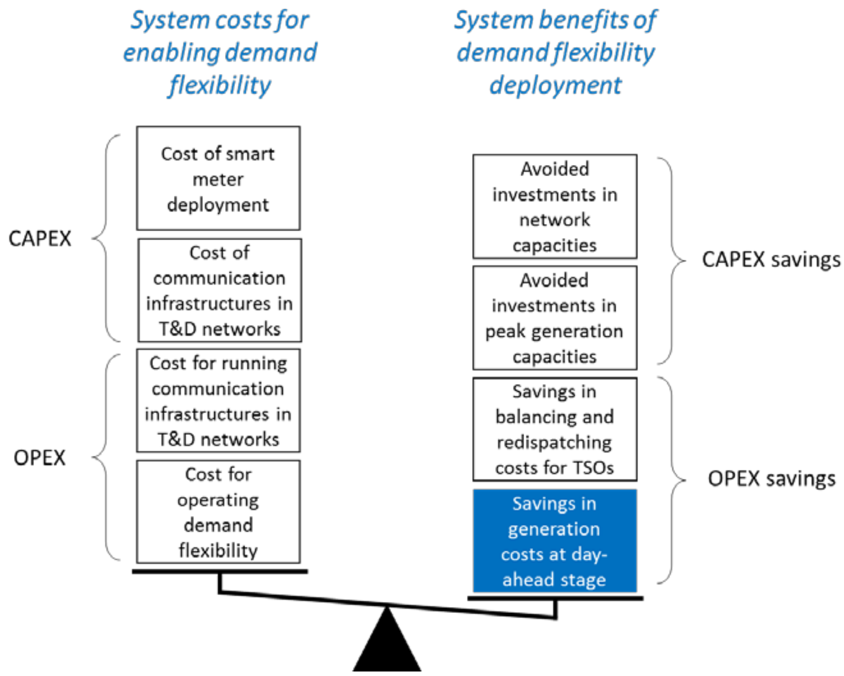
- At **system** level, benefits of demand response should exceed its costs (CAPEX and OPEX);
- Furthermore, the cost-benefit comparison must also be positive for each stakeholder participating in demand response:
    - At **network operators**' level (transmission and distribution), the costs for allowing demand response development should be evaluated and properly compensated;
    - At **market players**' level (retailers and aggregators), a business case must be found to make demand response programs profitable for them, being them implicit or explicit;
    - At **consumers**' level, the proper levers must be used to make demand response attractive (adequate combination between economic levers and societal aspects).

3.4.1 At system level

The global costs and benefits of demand response can be represented as shown on ***Figure 13***.

The blue box in ***Figure 13*** represents the benefits quantitatively assessed in the Market4RES study reported in section 3.2. Demand flexibility is indeed a way to avoid price peaks during high consumption periods and/or generation low availability periods. Demand flexibility can therefore bring **substantial benefits at the day-ahead stage** by avoiding the start of expansive peak units. Environmental benefits can be included in these **OPEX savings**, considering that CO_2 emissions savings are reflected in the generation costs savings through CO_2 price. Within our analysis, in the 11 countries included in the scope of our study these OPEX savings would range between 458 million of euros and 2.2 billion of euros.

Figure 13. *Comparing costs and benefits at system level of large-scale demand flexibility deployment*



These are not the only benefits of demand response; others can be categorized in three groups:

- **Other OPEX savings**: Consumers will compete with generators for balancing and redispatching purposes. This should lead to a decrease in balancing and redispatching costs (mainly borne by TSOs; but to some extent DSOs can also benefit from increased power flow control). Assessing the **savings in balancing and redispatching costs** is challenging. Furthermore, regarding distribution networks, the Commission staff working document [33] details the benefits for DSOs: *"Advanced monitoring and control due to smart metering infrastructure deployment allow for more efficient network operation (reduced technical and commercial losses) and more effective management of the system, particularly in the presence of growing renewable energy potential. Furthermore, increased distribution network efficiency and enhanced network management could ultimately lead to lower distribution network costs and better service for the consumers and increased revenue for the DSOs due to: (i) reduced technical and commercial losses, and (ii) improved reliability and power quality, particularly in the presence of growing renewable energy potential".* Still, as far as the authors know, these benefits have not been quantitatively assessed.[26]

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[26] In fact, Member States in their CBA have calculated benefits of smart meters deployment, each with their own method and scope. The EC staff document [33] reads: *"The estimation of benefits per metering point seems to also return a scattered picture of smart metering roll-out in Member States: the range of benefits varies significantly from as low as €18 (Latvia) to €654 (for Austria), as shown in Figure 8. On average for those Member States rolling-out the expected benefit per metering point is €309 (with a standard deviation of ±€170). Some caution is needed in interpreting these*

- **CAPEX savings:**
  - Assuming a constant level of security of supply, the deployment of demand flexibility should allow **avoiding investments in new peak generation units**. Assessing these avoided investments is also a difficult task. Still, it has been roughly done by Capgemini in [23]. They assumed that 1 GW of new production capacity would cost 400 million Euros on average, and that within EU-15 between 28 GW and 72 GW of peak generation capacity would be avoided: this leads to a range of 11 to 29 billion Euros in total (to be spread over the whole lifetime of the avoided investments).
  - Again assuming a constant level of security of supply, the deployment of demand flexibility should allow DSOs and TSOs to **avoid investments in additional network capacities** (in national networks and at cross-border level). Those savings have also been roughly assessed by Capgemini in [23]. They assumed a one to one saving: one euro saved in GW would equal one euro saved in transmission or distribution costs, which is in their view a "relatively conservative estimate". This leads to a range of 11 to 29 billion Euros within EU-15 (to be spread over the whole lifetime of the avoided investments).

On the other hand, the costs at system level of demand flexibility must be assessed to be compared with its benefits. Such costs can be categorized as follows:

- **Investment costs (CAPEX):**
  - First, demand flexibility is enabled only if smart meters are deployed at large-scale. The **costs for deploying smart meters** has been assessed within each EU-27 Member State when deciding upon the large-scale roll-out of smart meters, as described in the Commission staff working document [33]. This assessment has been done per metering point. The EC staff concludes: *"Among Member States' CBAs, there is a striking divergence of data on costs and benefits. Smart metering systems for electricity are costed at anything from €77 to €766 per customer, also reflecting differences in communication infrastructure costs; the average estimate is €223."* In addition, *"the range of values placed on costs and benefits may stem from different starting conditions in Member States, local realities and CBA scope and methodology. However, the divergence poses significant comparability challenges and complicates the exercise of calculating key parameters such as 'cost per metering point' and 'savings' consistently. It should also be noted that*

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figures given the different methodologies used to estimate benefits and the different items included in the evaluation: in fact, several Member States only accounted for the benefit associated with the DSO rolling out and not for the consumers' benefit or other benefits accruing to the society as a whole. The benefit attributed to the DSO is in general easier to estimate, as smart metering primarily implies savings in meter reading operations, switching, non-technical losses etc. In addition, advanced metering infrastructure allows for more accurate billing of electricity consumption. There are no benefit values available for Finland, France, Malta and Spain". Also to illustrate the difficulty in assessing benefits of smart meters, the EC staff [33] mentions: *"There are no benefit values available for Finland, France, Malta and Spain. France considers that the assumptions for the benefits calculation are too uncertain to give a reliable value"*.

the currently available figures are in most cases only a forecast and do not represent actual costs or benefits. Only as the roll-outs unfold will the consolidated figures become clear – what is shown is in most cases a projection. Furthermore, economic assessment of the long-term costs and benefits of smart metering across the EU is sensitive to a number of parameters. Energy savings, smart meter capital costs, data communication systems and the discount rate are the critical variables raised most frequently in Member States' CBAs. In addition, total smart metering investment itself appears to be influenced by local conditions (including local labour costs, geographical configurations, etc.)." For these reasons, the cost assessment done at Member state level would deserve to be supplemented by a more global analysis taking into account recent developments and experience feedbacks. In addition, to this cost (in general borne by DSOs) should be added the investment costs in smart appliances, in-home management systems, etc. (costs borne either by consumers, retailers or aggregators, depending on the chosen market design options as described in section 3.1.2).

   - Second, communication infrastructures need to be developed at distribution and transmission levels to make the most of the possible services provided by demand flexibility. There are several options to do so, as studied for example in the ongoing ENERGISE project[27]. ENERGISE is a European research project which does a cost/benefit analysis for smart grid infrastructure. The focus is on the core question: What should be the basis for the expansion of smart grids, independent proprietary communication networks of the electrical utilities or structures shared by the energy and telecommunication sectors? The final results of the project will be delivered in March 2017.

- Operational costs (OPEX):
   - First, network operators (DSOs and TSOs) will also bear operational costs for running the communication infrastructures needed for activating demand response services. These should also be part of the assessment carried out by the ENERGISE project. This is also discussed in section 3.4.2 below.
   - Second, aggregators or retailers will bear some operational costs for operating demand response programs, including marketing and contractual costs. These costs will depend on the chosen market design options (described in section 3.1.2, and discussed in section 3.4.3 below).

[27] See http://project-energise.eu/.

3.4.2 At network operators' level

Network operators need to properly assess the costs they bear for assuring demand flexibility deployment. In principle, these costs are borne by regulated network tariffs. On the other hand, the large-scale deployment of smart meters can also provide new opportunities and sources of revenues for the network operators (in particular at distribution level).

In a recent publication (January 2016), the DSO association EDSO for smart grids provides a vision about the regulatory environment needed to enable the "digitalization" of DSOs [34]. This includes the use and third party access to smart metering data: *"An open data approach can be made in combination with the smart meter. Reliable metering data that is anonymised or is aggregated could be made publicly available to help public administrations and market parties offer smart energy solutions"*. In addition, they position DSOs as the most adequate parties to organise the access to smart metering data – which is the basis for the deployment of demand response: *"As DSOs are already regulated and neutral parties, they are best suited to collect, store and manage consumer data to facilitate a secure, efficient and transparent platform for data exchange among market parties. DSO should be allowed to establish and upgrade platforms and protocols for exchanging smart metering data with transmission system operators and other market players without the appointment of a third-party manager."*

Several major European DSOs also participate in the FLEXICIENCY project[28], which aims at showing that the deployment of efficient novel services in the electricity retail markets can be accelerated thanks to an open European market place based on standardised interactions among electricity stakeholders, opening up the energy market also to new players at EU level: *"The services resulting from the proposed technical framework will empower real customers with higher quality and quantity of information on their energy consumptions (and generation in case of prosumers), addressing more efficient energy behaviours and usage such as through advanced energy monitoring and control services. Accessibility of metering data, close to real time, made available by DSOs - under customer consent - and in a standardised and non-discriminatory way to all players in the electricity retail markets (e.g. electricity retailers, aggregators, ESCOs and end consumers), will facilitate the emergence of new markets for energy services, enhancing competitiveness and encouraging the entry of new players and benefitting energy customers. Economic models of these new services will be proposed and assessed."*

The project will demonstrate different use cases of services enabled by the development of an EU market place catalyzing the interactions between relevant stakeholders in an open and standardised way. An economic evaluation of the selected use cases will be carried out to provide insights for actionable business model options and exploitation strategies preparing for business plans for the consortium partners.

[28] See http://www.flexiciency-h2020.eu/.

The results of the FLEXICIENCY project, which will end in January 2019, will be a crucial input to position DSOs with regards to demand flexibility services, evaluate the new opportunities for them and thus foster large-scale demand response deployment.

Regarding TSOs, ENTSO-E has recently published an overview of market design options for demand response integration in day-ahead, intraday and balancing energy markets [35]. They consider that there are six requirements for unleashing the potential development and efficient use of demand response:

1. **Price signals need to reveal the value of flexibility for the electricity system.**
2. **Efficient use of DSR is based on an economic choice between the value of consumption and the market value of electricity.** This choice arises when the consumer is exposed to variable prices or if the consumer can sell its flexibility on the market, possibly with the help of an aggregator.
3. **Access to price information, consumption awareness and DSR activation require strong consumer involvement, which can be facilitated with automation or by delegating the DSR process from the consumer to a company.**
4. **Regulatory barriers, when present, need to be removed to unlock full DSR potential, including barriers related to the relationship between independent aggregators[29] and suppliers.** Any evolution must preserve the efficiency and well-functioning of markets and their design components, such as the pivotal role of balance responsible parties, their information needs and balancing incentives. From a TSO perspective, the choice of the market model results from a trade-off between the imperatives not to increase residual system imbalance and to facilitate the development of additional resources.
5. **DSR should develop itself based on viable business cases.** Subsidies should remain limited and clearly identified.
6. **Communication and control technologies need to enable DSR for small consumers and provide guarantees on their reliability.**

ENTSO-E considers that we are in the early days of demand side response, therefore a certain period of testing and experimentation is required and that the choice of relevant solutions can depend on local context and conditions: over time, convergence of models will appear as a result of benchmarking and mutual learning.

3.4.3 At market players' and consumers' level

The economic evaluation of demand response deployment for market players (retailers, aggregators) and for consumers will highly depend on the chosen market design options (explicit or implicit, as explained in section 3.1.2 and depicted in ***Figure 11***). The way in which the added-value of demand response is shared between the three actors depends indeed on the model chosen and on the contractual specificities agreed between them.

[29] Aggregators independent from supplier's BRP.

Irrespective of redistribution aspects between these three types of stakeholders, the design of the products traded on electricity wholesale markets is also crucial to encourage demand participation, while they have historically been fit to generation specifics, as explained by SEDC in [18]. *Figure 14* below illustrates a range of choices when designing Demand Response programmes, and how different choices impact on likely levels of participation by the demand side.

Figure 14. *Range of choices that determine the level of consumer participation in the product*

Source: SEDC [18]

3.5 Conclusions for demand participation in short-term markets

Demand response is clearly a key in the future market design allowing for a massive integration of renewables. If the 2030 generation has not enough flexibility to follow consumption, the load will have to adapt itself. Thus, DSR development could be an appropriate answer to RES deployment.

Nevertheless, DSR development will meet these ambitious objectives only if some barriers disappear, such as: deployment of smart metering, deployment of effective and affordable communication means between consumers and DSR operators, development of control methods, and establishment of a fair competition between suppliers and DSR operators.

Development of smart metering is on the way. Massive investments have been decided by many states to allow DSOs to install smart metering at a large scale. These investments need to propose an efficient, affordable and fair access for DSR operator IT systems as well as they propose new flexibility for implicit DSR organised by suppliers. The fair regulation of the competition between suppliers and DSR operators must be taken into consideration to boost DSM growth. TSO and DSO research must go on to develop new neutral control algorithms to estimate DSR volumes.

Benefits of demand-side participation in short-term markets have been quantified by the Market4RES consortium. Those should range between 458 and 2,161 million of euros per year within the 11 countries included in the scope of our quantitative analyses, depending on the different scenarios considered (renewable penetration level, fuel cost, CO_2 price, etc.) and on the level of deployment of demand response. Still, additional benefits like demand participation in reserve markets and avoided investments in peaking units and in network infrastructures, would also need to be quantified in a transparent and rigorous manner.

To make sure that demand response can kick-off at large scale as soon as the economic conditions are met (in particular, sufficient price spreads are needed), technical obstacles should be removed, concerning the design of the products traded on the wholesale electricity markets. Many design options are available and need to be followed to develop the potential benefits of DSR. DSM can be valued on the energy market, on the balancing market, on the capacity market, and for ancillary services. For DSR investors, it is important to touch most of these markets with the same IT system. The integration of DSR in the design of these markets is a heavy responsibility and challenge for DSOs and TSOs in the next decade.

4 CONCLUSIONS AND WAY FORWARD

In this report, we have summarized and drawn conclusions from a significant part of the work done within the Market4RES project since 2014.

Within the first work stream of the project (focused on short-term objectives regarding power market design), we have discussed in detail two topics of utmost importance in terms of market development. For this we have used outcomes of previous work packages of the project, namely WP2, WP3 and WP4. [30]

First, we have discussed the short-term evolution of RES support schemes (Chapter 2). Given the anticipated obligation to move towards market-based schemes, we have assessed the impacts of this change on short-term markets. We have proposed a configuration of market-based schemes which takes into account the most recent publications and position papers. These proposals form the first part of the roadmap to move away from administrative feed-in-tariffs to market-based support schemes for RES. The second part of this roadmap (post 2020) will be detailed in upcoming deliverable D6.2 “Guidelines for implementation of new market designs for renewable energy sources beyond 2020”, as illustrated by ***Table 8*** below.

Table 8. *Organisation of concluding Market4RES reports (WP6 deliverables)*

Market design aspects	WP6 deliverable	Based on
Workstream 1: short-term objectives		
RES support schemes design up to 2020	D6.1.1	WP2, WP3, WP4
Participation of demand in short-term markets		
Other design features of short-term markets	D6.1.2	WP2, WP3, WP5
Workstream 2: long-term objectives		
New market designs for RES beyond 2020	D6.2	WP2, WP3, WP5
Design of capacity remuneration mechanisms	D6.3	WP2, WP3, WP5
Participation of demand in long-term markets		

Second, we have discussed the deployment of demand response, with a focus on demand response participation in short-term markets (Chapter 3). We have reviewed the different market design options allowing for such deployment, assessed the current development of demand

[30] See the glossary section (page 7) for the definition of the different work packages.

response in Europe, identified barriers and quantified the impacts of further demand response development. Finally we have discussed the necessary conditions for large-scale participation of demand in short-term markets: at system level, and for each individual player involved in demand response (consumers, retailers, aggregators and network operators), a business case must be found to make demand response attractive. Participation of demand response in long-term capacity or energy markets will be discussed in upcoming deliverable D6.3 dealing with the long-term nature of market design.

Features of short-term market design other than demand response and RES support may need to evolve up to 2020 in order to facilitate RES integration. Therefore, the present report D6.1.1 will be supplemented by another report D6.1.2 currently under preparation, focusing on other market design aspects up to 2020. Again, this report will use previous work carried out within Market4RES, namely from WP2, WP3 and WP5.

With these two reports together, the work stream 1 of the project will be concluded with concrete recommendations.

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