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COMMISSION STAFF WORKING DOCUMENT

European Commission guidance for the design of renewables support schemes

Accompanying the document

Communication from the Commission

Delivering the internal market in electricity and making the most of public intervention

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1 INTRODUCTION

The promotion of new and renewable forms of energy forms part of the Union policy on energy[1]. The market does not provide the optimal level of renewables in the absence of public intervention. This is due to market and regulatory failures: low levels of competition and unfair competition with other fuels, in particular subsidies for fossil fuels and nuclear energy, (including €26bn[2] for fossil fuel subsidies in 2011), the incomplete internalisation of external costs (air pollution and energy security), rigid electricity system design inhibit the growth of renewable energy[3].

To counter and correct such situations public authorities intervene. Public intervention at regional, national or local level, can take different forms. Examples include state aid to certain sectors or companies in the form of grants or exemptions from taxes and charges, the imposition of public service obligations, and regulation through general measures. While such measures are necessary to correct market failures and achieve the desired level of renewables, public interventions need to be well designed and proportionate to avoid additional market distortions. With growing renewables shares, poor design and implementation of public intervention has led to unnecessary distortions with regards to energy production, trade and investment in renewables. This raises the cost of the promotion of renewables and risks hampering both the further growth of renewables and the completion of the internal electricity market. This document elaborates the points contained in COM(2013)XXX, exploring best practice in managing the reform of support schemes and in designing the support framework for the development of renewables in a manner fully integrated with the market to increase their effectiveness. Although the focus of the guidance is on public interventions in electricity sector the principles established may be applied as well in other energy sectors e.g. in transport and heating. Factors external to the renewables sector inhibiting its growth are not all covered by this paper but are equally important to ensure that its full potential can be reaped. Subsidies to fossil fuels are a chief example of this, and heeding the European Council's renewed call for their phasing out will be key to achieve a level playing field in the energy market.[4]

2 THE REFORM PROCESS

All industries are affected by the regulatory environment in which they operate. In the energy sector, where there is a long history of public intervention, the changing regulation of the sector has an impact on how the market works and how investors participate in the market. Renewable energy producers have faced a range of frequent

[1] In accordance with Article 194(1)c TFUE.
[2] Sources: OECD and Commission. See Annex of Communication COM(2013)XXX for more details.
[3] See Commission progress reports COM(2013)175, COM(2012(271), COM(2011)31
[4] European Council Conclusions of 22 May 2013 (EUCO 75/1/13

changes to support schemes. Change is constant[5]. In the renewables sector, the regulatory risk that comes with such changes has a direct impact on capital financing costs, the costs of project development and therefore with the whole process of developing renewables.

Reform is indispensable, as support schemes should adjust to the falling cost of renewables. That is necessary both for compliance with State aid rules and in order to minimise costs to consumers and industry. However, there has been a recent drop in investor confidence. This is due to the economic and financial downturn, changing legal circumstances, some freezing of support and longer term policy uncertainty which leads investors to focus on sectors other than renewables, other markets and regions. Member States' reforms of national support schemes have changed tariff levels, actual scheme design, choice of technology, or the length of support granted. Irrespective of any need to change support schemes (and there have been poor design features needing correction), the manner in which the reform is carried out can influence the costs of renewables.

When devising or reforming support schemes, Member States should also take into account to what extent design features can be inherently built into the schemes to ensure they are flexible enough to account for changes in the development of costs and technologies and so minimise the financial support granted. Such design features should come from more market-based allocation mechanisms and support instruments and would alleviate authorities to some degree of ad hoc administrative revisions of the existing schemes and would provide market investors with more certainty about the legal framework

Credible and published plans

A common recent driver of changes to schemes has been the need to adapt rigid schemes (incapable of responding to falling production costs and thereby risking overcompensation and excessive demand for new installations). Making rigid support schemes more flexible is a desirable change (discussed further below), and there are some good examples of how such reforms can be undertaken *without* disrupting or discouraging investors. Their common feature is that plans for modifications were, prior to their adoption, subject to extensive and transparent public consultations.

In one instance, the authorities reached an agreement with all concerned producers to maintain the existing support levels, but to eliminate overcompensation through an agreed new levy. New investors would enter into a reformed support scheme with more flexible and market oriented design features. In another case, a Member State introduced a cap on capacity for receiving support, which when reached would trigger reductions in support.

Proper public consultations and transparency are important elements of all regulation and public intervention in the energy sector and should be welcomed. In other instances, Member States have introduced several unannounced measures that caught

5 For an overview of the evolution of RES-E support instruments see table 2 in Appendix I

investors by surprise, altered expected returns, and diminished confidence in the entire energy sector.

Best practice to manage the reform process constitutes:

- ***Long term legal commitments on the timing and phasing out of support***
- ***Devising a support scheme that is flexible enough to account for changes in the development of costs and technologies.***
- ***Announcement of automatic reductions in support depending on specified caps and/or lower technology costs***
- ***Planned review periods and no unannounced interim changes***
- ***Clear commitments to avoid changes that alter the return on investments already made and undermine investors' legitimate expectations***
- ***Wide and public consultation on scheme design (e.g. 4-6 weeks for routine changes)***
- ***Stable scheme financing in line with the EU-acquis linked to consumption and off-budget financing to avoid fiscal impacts and uncertainty***
- ***Keep costs transparent and separate from other system costs***

3 MARKET INTEGRATION

3.1 Choice and design of instrument of support

Different instruments can be used to support renewables production in the EU: The most commonly used ones are feed-in tariffs, feed-in premiums, quota obligations, tax exemptions, tenders, and investment aid (can be partially financed from structural and cohesion funds). Instrument choice also depends on the market technology, scale, timeframe and location[6]. The choice of the support instrument often determines the price exposure that renewables producers face. This range of market price risk in turn affects the expected rate of return, which is function of the project risk and capital costs.

The Commission has often called for **more market exposure** to be imposed on renewables producers. This is because competitive energy markets should drive our energy production and investment decisions efficiently and cost effectively. The choice of support instrument measure should be sensitive to policy objectives of technological innovation, as well as cost minimisation and the interplay with other policy instruments, notably the EU Emissions Trading Scheme (ETS) and energy taxation. Some degree of technological differentiation may therefore be necessary, in particular to promote technologies at an early stage of their development as well as for small and micro installations.

[6] See table 3 in Appendix I for an overview of the instruments. Further to that, there is a vast amount of subcategories by technology across the EU: 38 for hydro, 31 for wind, 74 for biomass, 42 for photovoltaic, 16 for geothermal, 17 for wave/wave/CSP.

In its recent Communications[7], the Commission explained that as renewables producers become significant players in the internal energy market, and as the energy market nears completion[8], public interventions developed to assist immature technologies enter nascent markets need to evolve. Moreover the efficiency and effectiveness of different instruments varies with circumstances; so as circumstances change, support schemes need to be reformed, instruments need to change and become market based and support levels will decline and eventually be phased out. This section explores best practice in the choice of instrument in current European energy market circumstances.

3.1.1 Competitive allocation mechanisms

Many of the instruments can be designed on the basis of costs calculated ex ante by competent national authority (see section 4.1) or via genuinely competitive tendering or auctions, to let the market decide the most competitive bid for the specified source of energy[9]. A well-designed auction can lead to significant competition between bids revealing the real costs of the individual projects, promoters and technologies, thus leading to cost-efficient support levels, and limiting the support needed to the minimum[10]. Tender/auction designs need to ensure there is sufficient competition to incentives lower prices and have low regulatory costs to avoid becoming a barrier to market entry, as well as avoid strategic bidding, and contain penalties for non-delivery.

Auctions may still require some ex ante calculation of energy costs by the agency preparing the scheme, partly to help avoid strategic bidding, and often include floor or ceiling prices. Also, auctioning systems may not be implemented easily in all cases (small scale, infant technologies, and administrative burden excluding small scale producers etc.) and thus any tendering process needs to be transparent, comparable, inclusive, applicable to the technologies and sectors capable of bearing the administrative burden, and also ensure that the desired capacity is actually built. In the case of onshore wind, Member States' use of auctions has reduced recently, particularly as a result of winning projects not being followed up or completed, as a result of flaws in the auction design.

Well-designed auctions would foster competition between technologies, and do not exclude less mature ones from entering the market. For instance auctions may include several categories/steps of support level to incentivise uptake of various technologies. This may lead to meeting medium to long term objectives of developing diverse technologies necessary to attain cost-effectively our energy goals. Maturing technologies need to be able to enter the market to further their innovative learning and cost-reduction curve as the benefits of varied technologies may only be reaped beyond the short term as is often the case with policies that change the *status quo*.

7 See Renewable energy: progress towards the 2020 target, COM(2011)31 and Renewable energy: a major player in the European energy market, COM(2012)271

8 See Making the internal energy market work, COM(2012)663

9 For an overview of Member States use of tendering see table 4 in Appendix I.

10 Ensuring competitive tenders is critical. There have been cases where lack of competition has resulted in strategic bidding resulting in high tariffs and overcompensation.

Well-designed auctioning systems would allow new and dynamic market entrants, limit the cost of support and can help provide regulatory certainty about expansion of installed renewables capacity. For renewable electricity, if used with feed in premium schemes and in a power system with adequate infrastructure, well-designed auction systems should provide the most cost-efficient conditions for delivering renewables.

Auctions are also a self-regulating, subsidy phase out mechanism, since competitive bidding with clear and certain rules will reward low cost technologies and eventually approach zero, as technology costs reach grid parity. There is some evidence of this already occurring in areas of well-resourced wind and solar power.

In some cases auctioning is not appropriate, such as for small scale producers or technologies not easily able to participate in spot markets or bear market risk.

Best practice for competitive allocation mechanisms:

- ***Tender for support with clear rules that foster genuine competition between bidders where- as default option, tenders put different locations and technologies into competition to each other***
- ***Tenders can be used to allocate different instruments such as feed-in premiums, investment support or green certificates***
- ***Tender for producers capable of bearing the administrative burden***
- ***Tenders need to ensure delivery, e.g. via penalties***

3.1.2 Maximising competition – short and long term considerations

Much of the current discussion of the cost of renewables focuses on the need to reduce costs today. As discussed above tendering for the desired volume of energy, across technologies and across all borders is the most economically efficient means of achieving this goal. This is also the essence of why Europe is creating the internal electricity market.

One aspect that is distracting from these measures to maximise competition are the rules or constraints Member States put on support schemes regarding the origin of the upstream components of energy. Requirements for particular energy feedstock or equipment to come from a given area disregarding the global market are contrary to the EU *acquis* and have an impact on intra and extra-EU trade. Other measures (such as caps, limits to participants in quota schemes, price restrictions) that distort competition and undermine the cost-effectiveness of national support schemes should thus also be avoided.

These measures do not benefit consumers or the European common interest: many other European industries have not been able to live up to global competition because there was a fragmented national approach which reduced the benefits available from European economies of scale.

Best practice constitutes:

- ***Avoidance of territorial constraints on the use of particular technologies, equipment or feedstock***

- ***Avoidance of using Green House Gas emissions, including from transport, as isolated criteria for support schemes (but as part of holistic EU sustainability schemes)***
- ***No unjustified restrictions or limitations affecting the access of renewable energy producers to the markets for energy products***

Without detracting from the principles of maximising competition and minimising the costs of developing renewable energy, temporal distinctions can make such considerations slightly more complex. In brief, efforts to reach given goals in the short term (e.g. a 20% renewable energy target for the EU by 2020) may not be identical to those needed to reach other goals in the medium or long term (e.g. renewables shares of between 55-75% by 2050 as illustrated in the EU Energy Roadmap 2050). New technologies, materials, industries, infrastructure, market innovations etc. will be needed in the longer term. These elements need to be reflected in policy measures today, if the longer term goals are to delivered cost effectively. This is why the Union and Member States have long term policies on RTD, technology development and innovation and industrial development. Such considerations also influence the cost effectiveness of renewables support schemes.

Support scheme design should also reflect the need to address longer term goals of fostering technological innovation, economies of scale, cost-reductions and spill-over effects that facilitate reaching 2020 targets and reaching 2050 decarbonisation goals sustainably.

Member States may also have a clear objective of promoting technology innovation in renewables to ensure the cost effective medium term transition to a sustainable energy system. In principle innovation is incentivised through direct R&D support. For projects of first commercial scale deployment of a new technology, environmental and technical performance criteria which are not included in the levelised cost of electricity (LCOE) (for instance, specific operational settings, carbon content, resource efficiency, other environmental impacts) may be relevant in selecting the appropriate technology to be supported.

3.1.3 Feed in premiums

Premium systems are an evolved version of feed in tariff system with varying degrees of market exposure for producers. The Commission considers, on the basis of its analysis of support schemes, that premium systems have several advantages compared to other instruments: they oblige renewable energy producers to find a seller for their production on the market and make sure that market signals reach the renewable energy operators through varying degrees of market exposure. A well designed premium scheme will also limit costs and drive innovation by granting support based on a competitive allocation process or including automatic and predictable adjustments on cost calculations, giving investors market signals coupled with foresight and the necessary confidence to invest.

Feed in premium schemes thus seem an appropriate means for taking into account national and European specificities. Compared to green certificate schemes, a feed in premium can provide a more predictable revenue stream for investment in new technologies which are not fully market ready. They also allow renewable energy to be sold on different market places (energy exchange, bilateral contracts) which can increase its value. This puts pressure on renewable energy generators to become more active market participants, via incentives to optimise investments, plant design and operation according to market signals. A premium's effectiveness in terms of market exposure varies depending on whether premiums are fixed or variable, and, in the latter case, how often the premium is adjusted (hourly, monthly, yearly) and whether there is a cap and floor price.

A variable or floating premium will automatically fall when electricity prices (and carbon prices[11]) go up. From a market perspective it may be considered to have the disadvantage of partly shielding the beneficiary from price signals, but from the investor perspective this may be precisely what allows the investment to take place at a reasonable cost of capital. A premium can be made subject to certain limits, defined to contribute to achieving the policy objectives and support system wide objectives where possible. For example, a floating premium can contribute positively to system management and to avoiding over-compensation if set to zero in all hours where the system price is either negative[12] or higher than the estimated average remuneration needed (i.e. price level beyond which no support would be needed).

A fixed premium ignores electricity price movements, which can result in over compensation if prices are higher than forecast (when setting the premium), or in losses if prices are lower. This higher risk may trigger higher capital costs. However in exposing producers to market price signals it can help optimise operational decisions (e.g. providing a disincentive for production in certain extreme situations such as negative prices). A fixed premium with pre-determined capacity limits also has the advantage of costs being more predictable.

Best practice for feed in premium schemes:

- ***Preference for feed in premiums over feed-in tariffs for technologies that are approaching maturity***
- ***Determine the form of premium - floating (with or without cap) or fixed – as function of desirable exposure of producers to price risk***
- ***No payment of premiums for production in hours where the system price is negative or above the level of remuneration deemed necessary[12]***
- ***Use of competitive allocation mechanisms for granting premiums***
- ***Planned volume based premium reductions for new installations, dependent on when they are approved, connected or commissioned***
- ***Regular, planned and inclusive reviews of premiums for new installations***

11 Premiums interact smoothly with the EU ETS.

12 A zero premium when electricity prices are negative risks penalising the renewable energy producer for inadequate system infrastructure and is only appropriate if the premium takes this uncertainty into account or is based on full load hours.

3.1.4 Quota Obligations

Obligations that require energy suppliers to purchase a quota of renewables (or green certificate representing the production of such energy) are also in use in different sectors in several Member States. Such instruments create a market between renewables producers and suppliers of energy which can trade energy or certificates at a price determined by them and other possible market players. In particular, such instruments expose the energy producer to market prices, since they must market and sell the energy itself on the relevant market and, if its renewable characteristic is identified separately with a green certificate, also sell and receive a market price for its "greenness". In most countries which have introduced quota obligations, a penalty is applied for non-compliance that effectively sets a ceiling on the price of the certificate/greenness.

Whilst exposing producers to the efficiency of market prices, such schemes offer significantly less revenue certainty for investors, in particular if there is no minimum certificate price. In principle such risk is normal for investments under market conditions and puts investments in renewables on the same footing with other generation investments. On the other hand, the rise in revenue risk raises the cost of capital, in some cases to such an extent that debt financing of some projects is not available. This not only raises the cost of developing renewables in general. It can have a secondary effect in the electricity sector of limiting provision of renewables only to large scale incumbents capable of "on balance sheet financing", or with access to cheaper debt financing. So in certain circumstances, these schemes can raise the cost of renewables.

However, the price risk for investments under quota schemes can be reduced by setting a floor price for the tradable certificates (with the level of the penalty usually forming a price cap).

Obligations can be created that are technology neutral, for maximising competition to drive down technology costs and achieve renewables growth at least cost in the short term. This is the case in the Swedish-Norwegian green certificate scheme for electricity, which deploys wind and biomass powered electricity with similar costs and has potential to reach national targets with those technologies[13]. Obligations can also be created with technology banding[14], where there is a wish to develop and deploy a variety of technologies, not all having the same cost. Some Member States offer in the electricity sector extra certificates for more expensive technologies (PV, offshore wind…) or impose separate technology-specific obligations for innovative, more expensive technologies in transport e.g. separate second generation biofuel blending obligations). Technology banding is also a means used by several Member States to avoid over compensating cheaper technologies that enter the market at high prices set by more expensive technologies.

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13 Although cheaper combined heat and power plants may be able to profit from green certificate prices set by higher cost wind projects.

14 Technology banding allows setting different support for different RES technologies.

Best practice for quota obligation schemes constitutes:

- ***Technology neutral schemes that promote cost efficient deployment or banded schemes to avoid over compensation of cheapest technology and to reflect explicit technology innovation and diversification goals***
- ***Schemes based on long term transparent and planned quotas***
- ***Adequate non-compliance penalties***
- ***Market data available to all stakeholders***

3.1.5 Investment support

Upfront investment support generally covers capital costs and is distinct from operating support which covers operating or production-based costs. Investment support takes various forms, the main types being grants, preferential loans and tax exemptions or reductions.

Whilst operating or production based financial support is viewed critically because it maximises production irrespective of price, investment support decouples production from the sales price and can be appropriate when production incentives are not necessary or desired (e.g. not producing excessive heat generation during summer months when demand is low) or where the market provides an adequate and efficient production signal – for instance for more mature technologies with high up-front investment costs. In practice, limits on the availability of short term financial resources can be a constraint on the use of such upfront investment support for large scale energy investments, particularly when government budget-financed.

In many Member States support is provided on a sub-national level, e.g. it falls under the responsibility of regions or even municipalities. In current practice, a lot of support for renewable energy heating, particularly at household level, occurs with investment support. Technology demonstration plant funding is also more common as investment support.

In many Member States, investment support is provided by EU funded instruments (the European Agricultural Fund for Rural Development EAFRD, the European Regional Development Fund ERDF[15]). This type of support is to be coordinated with other national or regional support schemes, which have to be taken into account when the maximal aid intensity under EU funds is assessed.

Investment support[16] also has the advantage that operating costs are in principle not affected. Moreover, it is a one-off measure which does not need to be readjusted at a later stage due to developments in technology or markets to avoid overcompensation.

Best practice for investment support constitutes:

15 The MFF has enshrined priority to the promotion of RES. Member States shall in particular devote between 12% and 20% of their ERDF allocations to support the shift towards a low-carbon economy, including the promotion of energy derived from renewable sources.

16 For technologies with very high capital costs, "operating" support unrelated to production is equivalent to investment support.

- ***Where feasible, favour investment over operating support so as to avoid distorting efficient production decisions based on market price signals***
- ***Ensure cumulative investment support does not over compensate producers***

3.1.6 Tax exemptions

Tax exemptions and reductions are used extensively in the energy sector. In the renewables industry they are used at industry level often to encourage biofuel production, and at household level to encourage household investments (e.g. rooftop PV).

Tax exemptions are financed indirectly by all taxpayers, since public revenues are reduced, rather than by energy consumers. They are therefore subject to the political and economic currents that shape fiscal policy in general. Under Directive 2003/96/EC[17], tax exemptions or reductions for biofuels, granted under certain conditions and normally subject to state aid control (avoiding for example over compensation and distortions of competition), are allowed. In addition, the Directive allows tax exemptions or reductions for electricity, produced of solar, wind, tidal, geothermal and hydraulic origin. That said, the Commission services believe that such instruments should be used with caution, not least given the need to uphold the budgetary consolidation efforts of Member States.

Use of (renewable)[18] electricity in transport is also promoted in some countries through reduced purchase taxes on electric and hybrid vehicles.

3.1.7 Feed in tariffs

The Communication recommends that feed in tariffs are phased out and support instruments that expose renewable energy producers to market price signals such as feed in premiums are used.

The general trend in the numerous changes of support schemes over the last years is a move from feed in tariff to premium models[19]. Feed in tariffs insulated new market entrants from price risk – from the market – thus lowering their cost of capital and enabling private investment. Feed in tariffs are also amongst the most simple of schemes to implement, making them suitable for markets with a large number of less commercial participants (e.g. households or local community based initiatives).

Despite such advantages, it must be remembered that feed in tariffs exclude producers from actively participating in the market and thus hinder efforts to develop large liquid electricity markets as the share of renewables grows. Major negative features of feed in tariffs and other support that have been revealed in recent years include the

17 Council Directive 2003/96/EC of 27 October 2003 restructuring the Community framework for taxation of energy products and electricity, OJ L 283 of 31.10.2003

18 Cf. accounting rules in COM(2009)28/EC Directive on the promotion of the use of energy from renewable sources

19 A notable exception is the recent decision in January 2013 by Spain to abolish the feed in premium scheme and revert back to a feed in tariff.

impairment of flexible and liquid markets, limiting growth to certain technologies and sizes of installations and the difficulty in setting appropriate tariff levels and in adjusting such tariffs. Setting the tariff (and other support) levels are discussed in Chapter 4 below. The adjustment of support levels can be planned in advance, to allow adaptation to reflect changes in costs. For instance, existing tariffs may be constant for the full period (assuming capital costs are constant), or, variable/declining if capital costs can be adjusted over the period. The tariffs for new installations should also be flexible to adjust quickly to lower production costs. A third form of tariff flexibility introduced in some schemes recently has been a volume induced degression in the tariff: if costs of new installations fall faster than expected and growth in installations grows beyond reasonable expectations, a volume ceiling can trigger a reduction in the tariff. Where the constraint is financial, the ceiling could be based on support expenditure rather than volume.

There are only a few situations where tariffs may be more appropriate e.g. when supporting small scale activities (with *de minimis* market impact involving investors who cannot reasonably be expected to participate in wholesale markets).

Recently the low investor risk provided by feed in tariff schemes has been put in doubt as regulatory risk in certain countries resulted in higher than previous capital costs for investors under such schemes.

Best practice for feed in tariff schemes:

- ***Phase out of feed in tariffs (may be appropriate if combined with a pre-set capacity cap (per technology or market segment) for small scale activities and/or in non-developed markets)***
- ***Tariffs need built-in cost-based or expected cost-based reductions in tariff levels for new installations (in line with learning curves and expected future cost reductions in various technologies)***
- ***Planned volume based tariff reductions for new installations, dependent on when they are approved, connected or commissioned***

3.2 Minimising system impacts on power markets

Experience shows that the level of support alone does not necessarily determine success in terms of renewables production. A well-designed support scheme needs to be embedded in a coherent policy framework. Support schemes work best when they are part of a long-term predictable and stable policy/strategic framework with clear objectives.

Support for renewables can be implemented in a variety of ways with differing impacts on how the market functions. Whilst the Commission has been clear that such interventions are warranted, the means of providing the support can be more or less distorting (less or more corrective), depending on the instrument applied.

The following elements of balancing, grid connection and dispatch influence to what degree renewable electricity producers are and can be integrated effectively into the power markets. Good administrative practice is relevant for all support schemes to bring costs down and ease market entrance also for new and smaller players.

3.2.1 *Responsibility for electricity grid balancing: need for intra-day and cross border dimension*

The majority of existing electricity grid infrastructure and wholesale markets were designed to accommodate **centralised and dispatchable national power** output from conventional thermal and hydro-electric plants[20]. Most of the new capacity that comes online in the Union currently is variable renewable energy: wind and solar.

Initially when wind and solar electricity started, it had no balancing obligations, which were borne by transmission system operators (TSOs) or other entities. This was because such producers constituted a small share of the market and because system operations and market structures could not support such obligations at low cost. As the share of wind and solar power grows and as system technology and markets evolve, the **system architecture** is becoming flexible in a variety of ways. A reinforced, interconnected European grid, coupled markets, flexible production[21], increased backup and storage capacity, demand response measures, clear price signals[22], responsiveness of support to these price signals and a diversified deployment of renewables both with regard to technology as well as on many good sites in order to balance the fluctuation of RES across Europe all improve the functioning of the electricity system and market and its ability to absorb wind and solar power. As such, a broader allocation of balancing responsibilities becomes feasible.

As national markets integrate[23] into regional markets cross border trade of electricity increases[24]. Larger balancing zones with sufficient internal transmission capacity can facilitate the cost-efficient integration of renewables. TSOs have to look beyond their borders to *Europeanise* their thinking and make use of backup and storage options located in other Member States[25]. Market players have to be able to freely operate across borders.

Balancing obligations currently vary between Member States. Some 16 out of 28 EU Member States include some form of financial obligation for balancing for all power

20 OECD 2012, COM/TAD/ENV*JWPTE(2012)20/REV1. See tables 5a and 5b in Appendix I for grid connection issues and solutions for RES in EU Member States.

21 Ramp rates vary from seconds for PV to several hours for larger thermal power plants,

22 Currently consumers are often exposed to regulated prices in the EU, thus making demand response inexistent with a nearly vertical demand curve. Regulated or capped prices to guard against high prices can discourage necessary investment signals to address, in turn leading to calls for additional mechanisms to ensure supply security in the power sector. Inevitably investors have to bear some risk and cannot expect the risk to be carried by the consumers only. Leaving the market free to set the price is a core part of Europe's current market liberalisation.

23 Market integration means the process of step by step harmonising the rules of the various power markets, culminating in the harmonisation of all cross-border market rules that allows electricity to respond to price signals and flow freely across borders (as do goods and services in the internal market).

24 This is foreseen with the implementation of the “target model” and its provisions for continuous intra-day trading, which will result in cross-border exchanges (schedules) being notified closer to real-time.

25 Flexible power generating plants are by nature located in different locations where the resource is abundant (hydro pumped storage, combined-cycle gas, biomass, power to heat, etc.) even if new technologies are developing. See Commission Communication "Energy Technologies and Innovation" [COM(2013) 253]

sources including renewable power producers[26]. For resources to be used flexibly and cost effectively across the EU, all producers in the market should bear clearly defined balancing responsibilities where, of course, adequate price signals from competitive power and balancing markets reach producers.

Such changes require the implementation of all the elements of the 3rd electricity market liberalisation package, where operators are able either to undertake the balancing themselves or, particularly for small producers, outsource this to other balance responsible parties via commercial arrangements. Aggregating several producers improves efficiency, benefitting from more varied assets to manage overall output, particularly when occurring across borders, where aggregators are able to take advantage of further geographical and technological diversity, as well as variations in peak hours.

Harmonising such obligations depends on the *possibilities* for balancing in each Member State and these also vary. Most Member States have **intra-day markets** but with different **gate closure times**[27]. These differences can cause inefficient power flows from high price to low price zones and also impact greatly on the costs of different power producers and their ability to meet balancing obligations. Conventional power plants can be dispatched to meet demand patterns at any time scale, subject to technical ramping restrictions. Significant quantities of renewables are also easily "dispatchable" (biomass and geothermal and large hydro). Others of course (run of river hydro, wind, solar), have much shorter high probability time frames to predict their power output. For instance wind power production forecasting[28] certainty is close to 98% for two hours ahead, but beyond 24 hours the error margin rises[29]. Shorter gate closure times thus favour the inclusion of wind and solar power, while longer gate closure times reflect traditional power systems. Intraday (and ultimately seamless) trading can reduce the impact of remaining forecast errors of growing wind shares. Liquid intra-day trading where short term transactions between participants in the market leave little residual imbalances for TSOs to manage are most efficient and should be pursued[30]. Harmonised practices across Member States are even more important as market coupling[31]progresses, since market participants place their bids for various national power markets.

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26 See table 6 in Appendix I for an overview of RES-E balancing regimes in the EU.

27 The gate closure time of the market power exchanges is the time limit for committing to the delivery of electricity at a defined moment. See table 7 in Appendix I for gate closure times.

28 Forecasting is important also to keep overall costs down. Adequate forecasting for wind and solar power allows grid operators to plan ahead for surges in cheap and clean wind power, and consequently reduce costs by ramping down more expensive and polluting thermal power plants. If this is done on the regional level, then forecasting accuracy can increase further (individual wind project forecast errors tend to cancel each other out) with consequent benefits also allowing the removal of much of the uncertainty associated with electricity bottlenecks.

29 Forecasting for wind has improved over the last decade with evolving IT systems, but still has its natural limits.

30 Measures for the improvement of the intra-day market include: change from day-ahead spot auction to continuous spot trading until close to physical gate closure; move the gate closure time for the spot auction e.g. to 6pm on the day before; bundle liquidity by introducing auctions in the intraday market and increase liquidity by obliging market partners to bid into the intraday market.

31 Market coupling is used to allocate capacity on interconnectors between national power systems, linking wholesale markets via an implicit auctioning that decides efficient cross-border flows reflecting price differentials amongst participating markets. The result is that electricity flows from the low to high price zones.

Best practice constitutes:

- ***The application of network codes (gate closure, balancing obligations...) which do not discriminate against variable (such as wind and solar) power producers but enable their full participation in the market.***
- ***The creation of competitive balancing and ancillary services markets (plus public commitment to attain this target)***
- ***Equal allocation of balancing responsibilities for all producers in line with technical capabilities once liquid and well-functioning balancing markets are in place***

3.2.2 Electricity dispatching rules

To help access the market, renewable energy has been granted **priority dispatch rights**, under Directive 2009/28/EC, where centralised dispatch occurs. This helps new technologies and market players enter the market dominated by centralised large power producer incumbents because it insulates renewable power from volume risk. But as markets evolve (and open), and as grid operations become more neutral, such priority may become unnecessary. When renewables producers are able to take part in offering power to the market directly, they, like other producers, seek a power purchaser and sell their power accordingly (except for feed in tariff support schemes). Moreover when renewables producers have equal access to the market, their low operating costs (particularly for wind and solar power production) place them before conventional power producers in the merit order. As such, systems with centralised dispatch fade and priority dispatch rules become less relevant for renewable energy technologies active in the market.

Separate from priority dispatch, the interdiction of significant **curtailment** of renewable energy contained in Directive 2009/28/EC was introduced to ensure that renewable energy producers should not be penalised for infrastructure inadequacies as well as to protect them from possible non-competitive behaviour of imperfectly unbundled TSOs. Member States National Renewable Energy Action Plans, translated into the Ten Year Network Development Plans, together with the improved framework for developing electricity infrastructure contained in the proposal for a regulation establishing the Connecting Europe Facility (CEF:COM(2011)665) should ensure that electricity infrastructure keeps pace with the changing power generation mix. This, together with the increasing flexibility of the system (including storage and demand response able to absorb hitherto excess supply) may also render such rules less relevant or necessary.

3.2.3 Responsibility for grid costs

It is important to have cost transparency for all generators accessing and connecting to the power grid, and non-discriminatory rules are foreseen by the electricity market and Renewable Energy Directives. Increasing consistency in the way that Member States charge both grid connection fees and network tariffs is important for creating an effective internal electricity market. However, while **differences between Member States'** charges for generators using the grid infrastructure persist, there are also limits to guidance on best practices that can be given in terms of how to treat renewables producers.

As with other aspects of the electricity system, national practices regarding the financing of new, as well as existing infrastructure differ considerably and have evolved as markets are "unbundled". New entrants (often renewable energy producers), have to bear widely varying connection costs depending on the national regime[32]. Imposing these costs on new producers causing the need for new grid construction risks reducing incentives to locate production where the resource is optimal ("wind where the wind blows", "sun where the sun shines"). It also risks imposing the costs of creating a *socially* optimal infrastructure on the marginal producer (in the same way that the costs of interconnectors should not be borne by individual users or indeed, single Member States). For this reason, further consideration of shallow cost charging regimes is necessary[33].

Best practice constitutes:

- ***Transparent and non-discriminatory cost allocation rules for all power producers***
- ***Common grid rules (balancing, tariffs, gate closure etc.) for coupled markets***
- ***Shallow network connection regimes (enabling system wide optimisation and cost sharing)***

4 KEEPING COSTS LOW

As markets and technologies mature and the costs of many of renewable technologies energy go down, the financial support to renewables will gradually decline, apart from R&D expenditure to immature new technologies with good long-term potential.

Beyond the actual support scheme under which renewables are produced, the overall framework conditions have to be levelised as much as possible across sectors and countries so as to ensure cost-effectiveness and avoid distortions. Converging national support schemes under these conditions will allow spill-over effects to take place from the international project development expertise and technology supply chain.

32 Ranging from shallow charges where costs are averaged and shared over all producers, to deep charges, where specific connection costs are borne by each producer. For an overview see table 8 in Appendix I.

33 Shallow connection cost: to charge generators for the cost of connecting the power plant asset to the nearest point of interconnection with the public electricity network only. Deep connection cost: to charge generators additionally for (part of the) cost of network expansion/reinforcement engendered by the connection concerned.

4.1 Cost elements and calculation methodology

The current methods of calculation as well as the cost elements taken into account in the process of setting national support levels vary greatly[34]. This affects not only stakeholders and their investment decisions, but also public opinion.

In addition to the use of competitive allocation mechanisms discussed above, applying the same method of calculating costs to ensure the competitiveness of the mechanism minimises distortions of competition and trade. It would also help bring down costs by addressing the information asymmetry problem when setting support levels. As a general rule, Commission services believe that allocation mechanisms for public support which make market players reveal as much information as possible during the process and which adapt to changing market circumstances are therefore preferable. It is only if the market information or competitive allocation mechanism is not reliable for example due to a limited number of market players or very immature technologies that public authorities should need to base their calculation of support on administrative procedures involving detailed cost calculations.

The vast majority of national support systems (even support schemes coupled to tendering) include at some point the calculation of the support level (e.g. for setting a cap for specific technologies in competitive allocation mechanisms). Calculations are based on information from industry, world markets, etc. There is a risk of information asymmetry between stakeholders and the government authorities. In essence, industries (often national) present their cost estimations for the years ahead and the legislator sets the support level accordingly (via tariffs or certificates etc.). Furthermore, many countries have Parliamentary scrutiny of the support levels which results in final support levels that are even more complex and difficult to predict, reflecting national political preferences of certain technologies and the strength of their respective lobbying. This situation is not ideal for investor certainty despite the binding 2020 targets.

There can be a variety of reasons for differences in support levels. First, they can reflect real differences in the costs of renewable energy generation in the Member States that result, for example, from the diverse availabilities of primary resources or stage of development. Secondly, renewable energy targets can contain different levels of ambition. Thirdly, the different support levels can be due to different type and design of support schemes applied in the Member States that lead to different cost-effectiveness. Differences can also stem from diverging methods for allocating grid costs, different level of administrative costs and, importantly, from different costs of capital. Finally, the differences can result from different methodologies in setting the support levels.

Setting the level of a technology-specific cap or of support

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34 See table 9 in Appendix I for examples from EU Member States of processes for calculating support levels. See the SETIS energy production cost calculator for a potential common EU tool: http://setis.ec.europa.eu/EnergyCalculator/

In the case of competitive allocation mechanisms, cost calculations can serve as a reference for policy makers or as benchmark for technology-staggered auction processes. Cost calculation involves a number of distinctive steps: starting with the selection of cost parameters (see list of recommended parameters in best practice box below) and cost calculation methodology, followed by setting the cost and revenue projections, and finally transferring the levelised cost of electricity (hereinafter: LCOE) into an actual support level. In all of these steps, there are differences between the methodologies across Member States. This is partly due to different support instruments that entail different methodological requirements. There are also differences between Member States in terms of how well the process of setting support levels is documented.

In a first step, the large majority of Member States apply an approach based on project related costs, rather than avoided costs or societal benefits. The cost parameters used vary though between Member States (e.g. in the way market and network integration costs are considered. Where similar project cost calculations or estimates of the LCOE are used by Member States, they are not a major source of differences in support levels between Member States. Ideally, if all systems were to apply the same equation *and* the same input parameters, it would make systems more comparable. The Commission services consider the LCOE method as best practice.

Since support is intended to cover the gap between costs and revenues, as a second step, adequate revenue projections have to be made. This can be as demanding as establishing costs and adds another dimension of uncertainty and differentiation to the process of determining the cost calculation.

Finally, the LCOE needs to be translated into the actual parameters of the support scheme. Especially in support schemes where renewables plants are integrated in the competitive electricity market and receive part of their revenue from this market, support scheme parameters like caps and floors for premium payments or certificate prices can influence the actual support level which plants receive. In these cases, it is often difficult to assess ex-ante how these support parameters interact, for example, with electricity price development and how they affect the effective level of support. The actual support level thus becomes more dynamic and can be evaluated only ex post.

In the case of auctioning being coupled to a support scheme, the bidders will submit offers to obtain public support based on their own cost estimates inherent in their offers. In this situation, cost calculations may however serve as a reference for policy makers or as benchmarks for staggered auction processes.

Best practice process for determining costs:

- ***Rely as much as possible on competitive allocation mechanisms to force market players to reveal their real production costs***
- ***Cost base calculation should be based on project costs, and for operating support, at least include the following cost parameters:***

- Equipment cost (Union cost benchmark for technologies) e.g. turbines, control systems

- Other investment and planning costs (construction/installation costs, foundations, buildings)

- Land (access to land, purchase/lease)

- Administrative costs included in support

- Capital cost (debt, equity)

- Operation and management costs

- Decommissioning costs

- Fuel costs (if relevant)

- Common cost assessment for grid connection / grid reinforcement

- Network-related costs (depending on the network access regime)

- Costs of market integration, e.g. balancing costs

- ***Expected <u>revenues</u>***

- Calculated in advance

- Adjustments ex-post for differences between the agreed, expected revenues (including sales of guarantees of origin, tax reductions and other advantages) and actual revenues, to avoid over compensation

- Technology specific load factors

- ***Caps and floors that influence the level of support and they should be linked to the above cost analysis.***
- ***Differentiate between technologies and site qualities while respecting principle of competition between producers, technologies and locations***
- ***The support level based on LCOE calculations***
- ***The analysis of cost parameters should be based on country-specific studies that are transparent and validated through stakeholder consultations***
- ***Support levels aligned with other support instruments (e.g. EU regional funds) limit the aid to the minimum.***

4.2 Automatic tariff digression

Support levels have to be set transparently and include all relevant cost elements as set out in the best practice checklist above. But support systems have to be a dynamic concept regardless of the way in which they were set initially. They have to remain flexible enough to adjust as technologies evolve on the global market thanks to steep learning curves and technological innovation that bring costs down, and to the evolving market price of electricity. Schemes should thus include automatic degressive elements and be complemented by a built-in revision mechanism. They should also include transparent and predictable stakeholder consultations to prevent policy making being captivated by a certain part of industry. This common element would lead to further EU wide convergence and comparability, as well as help preventing over compensation and address public concerns thereof.

Best practice constitutes:

- ***Periodic review and adjustment of support levels for new installations***

- Process for the review should be defined ex-ante and be automatic

- Determine what constitutes excessive growth and set a volume limit defined in budgetary terms if expenditure is the policy constraint motivating such a cap

4.3 Time frame for support

Comparing the practice in Member States, the time limit for allocated support is, yet again, very diverse. For PV technologies alone, time frames for support in Member States range from less than ten years to over twenty years, with the a majority offering support for between eleven and fifteen years.

These differences in many instances apparently do not at all – or not only – reflect the higher or lower irradiation levels between countries and the resulting longer lead times it could take to make a return on investment provided the same support level is given (which is not the case). Instead, varying administrative cost burdens related to PV projects and the resulting longer lead times to make a return on investment, often seem to be at least as decisive.

Greater convergence of time limits for support could be beneficial for investor clarity. Shorter support periods lead to lower interest rates to finance projects, and equally carry a smaller risk of regulatory change as has recently taken place too often, though shorter periods also increase the support intensity.

An alternative to formulating time limits in terms of years is to limit support in terms of "number of full-load hours supported". This approach consists of converting the number of years that would otherwise have served as the time limit into a fixed amount of accumulated production for which support will be given using a reasonable assumption about the average/typical capacity utilisation factor of the type of installation at hand. This approach has important advantages:

Firstly, it provides more upfront certainty to public authorities (or consumers) about the total accumulated costs over time of a give scheme; if installations benefitting turn out to produce with capacity ratios above the assumed one, investors will simply receive their support earlier, but will not receive more. As such it eliminates an important source of potential over-compensation.

Secondly, it provides investors with more certainty on the total accumulated level of support they will receive without removing their incentive to invest in efficient and well-located installations (because these will still result in the support being disbursed more quickly than for inefficient installations).

Best practice constitutes:

- ***Limiting support to comparable periods (10/15 years)) or to a pre-set number of full-load hours calculated based on reasonable expectations for capacity utilisation over a defined period.***

(The longer the time frame, the greater the need for flexible, market-adapting instruments)

- ***Simple and transparent administrative rules that facilitate competition and do not discriminate between companies and minimise project delays[35]***

5 EUROPEANISATION OF SUPPORT FOR RENEWABLES

A working single market is necessary to fully exploit synergies of generating renewable electricity and producing sustainable biofuels.

In the Communication, the Commission envisages that renewables support schemes can be made more cost-effective through convergence of common methodologies, reducing restrictions for cross border access and making use of cooperation mechanisms.

As a consequence of public interventions, investors can choose one market over another to take advantage of better or more certain revenues. This could lead to some Member States suffering from less investment. Ideally investors chose the most efficient locations and benefit from similar investment conditions throughout the internal market. The existing cooperation mechanisms foreseen in the Renewable Energy Directive have not yet been used sufficiently in this respect[36].

There is some merit between competing national support schemes[37], in particular in the early stages of support scheme design. The Commission services consider that at present convergence towards comparable and compatible systems bring about more benefits overall, in the medium to long term. First steps towards more EU-wide convergence of the support schemes are convergence of cost and technology categories, the methodology of determining costs (including competitive allocation processes), time limits for support, grid obligations of renewables producers and making support systems market based.

Europeanisation can not only come through more convergent support schemes, but also through moving renewables to the competitive and increasingly integrated internal electricity market, i.e. phasing out support for renewables technologies as technologies mature. This is provided that the market and/or public interventions will be able to deliver sufficient investment incentives to renewables in line with policy objectives.

Market integration is the only pathway to further increase renewables in the most cost effective manner. A properly functioning market (new grid codes, more interconnections, real competition, harnessing flexibility of the system etc.) will be

[35] See more details on administrative issues in Table 10, Appendix II.

36 See Guidance on cooperation mechanisms.

37 Regulatory competition between EU Member States for renewable energy policy will most likely lead to a certain natural convergence as Member States design their support mechanisms to attract capital and ensure they meet their national renewable energy targets.

able to deliver renewables growth at least cost to society. Differences in natural resource availability and investments conditions lead to different cost structures in Member States. Convergence of methodologies may therefore lead to different outcomes of the level of support.

Member States are also encouraged to progressively open up their support schemes to renewables from other Member States reflecting market integration and physical flows of electricity.

In parallel, the existing cooperation mechanisms have great untapped potential to further Europeanise renewables. Sweden and Norway's joint scheme has the potential to be expanded further to include more countries that wish to do so or can serve as a model for other regions in the EU. In the same way the single energy market is coming together via the regional approach, this is mirrored for support schemes.

Best practice towards Europeanisation:

- ***Full implementation and respect of the internal market legislation for gas and electricity, in law and in practice***
- ***Common use of cost elements for calculating costs and calculation methods as described in this document***
- ***Extended use of various forms of cooperation mechanisms***
- ***Acceptance of energy supply from other Member States in national support schemes through creation of cross-border support schemes at regional or EU level through cooperation mechanisms***

6 APPENDIX I

Table 1: Overview evolution of RES-E support instruments

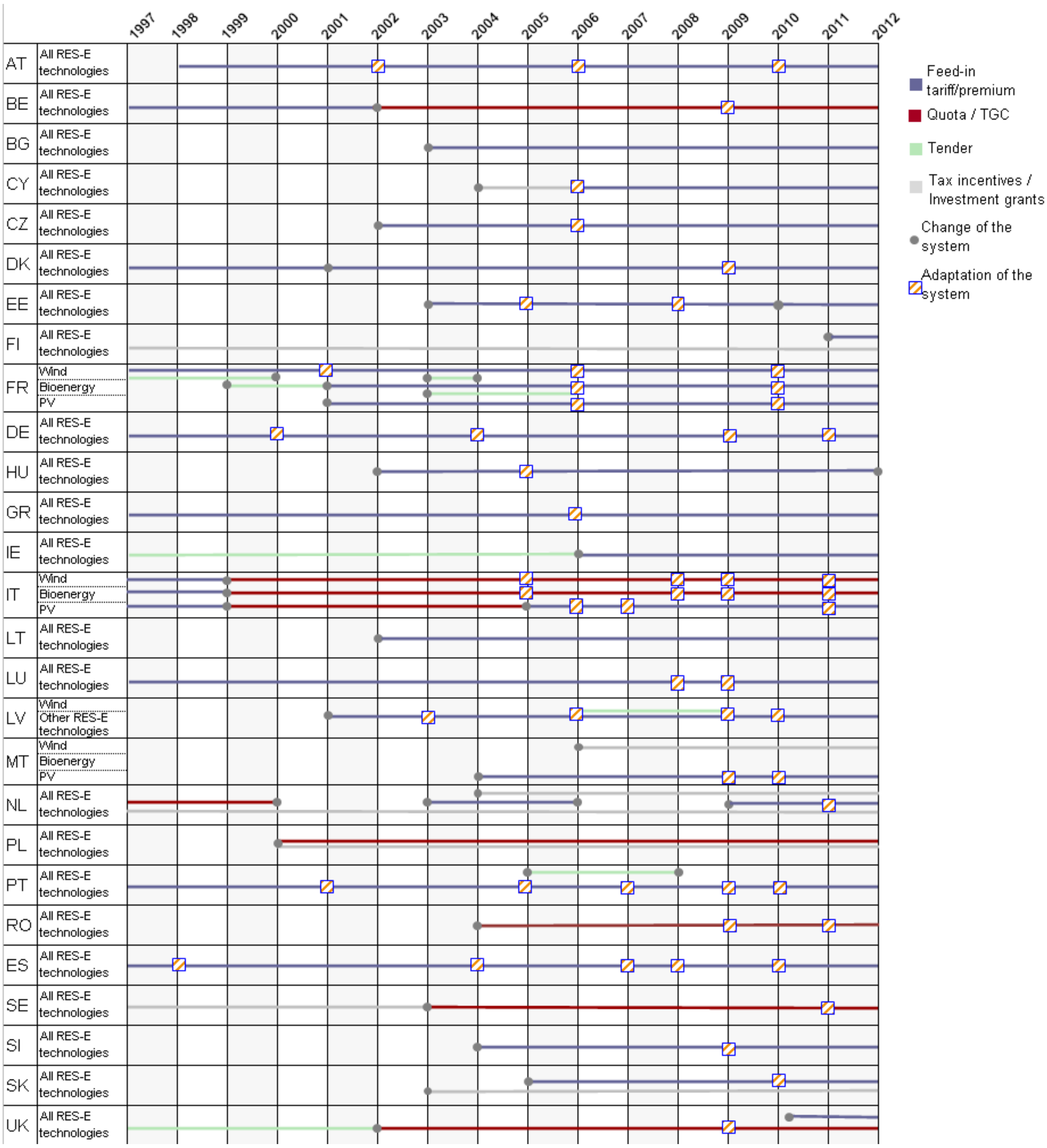

Table 2: Support instruments for RES-E

	Support instrument
Austria	FiT, Subsidy
Belgium	Net-metering, Quota, Subsidy
Bulgaria	FiT, loan, Subsidy
Croatia	FiT, Loan
Cyprus	Premium, Subsidy
Czech Rep.	FiT, Loan, Premium tariff, Subsidy
Denmark	Loan, Net-metering, Premium tariff, Subsidy
Estonia	Premium tariff, Subsidy
Finland	Premium tariff, Subsidy
France	FiT, Tax regulation mechanisms
Germany	FiT, Loan, Premium tariff
Greece	FiT, Subsidy (soft loan), Tax regulation mechanism
Hungary	FiT, Subsidy
Ireland	FiT, Tax regulation mechanisms
Italy	FiT, Quota system, Premium tariff, Net-Metering, Tax regulation mechanism
Latvia	FiT
Lithuania	FiT, loan, Subsidy, Tax regulation mechanism
Luxembourg	FiT, Subsidy, Regulation mechanism
Malta	FiT
Netherlands	Loan, Net-metering, Premium tariff, Subsidy, Tax regulation
Poland	Quota system, Tax regulation mechanism
Portugal	FiT
Romania	Quota System, Subsidy
Slovakia	FiT, Subsidy, Tax regulation mechanism
Slovenia	FiT, Loan, Premium tariff, Subsidy
Spain	FiT, Premium tariff, Tax regulation mechanisms
Sweden	Quota system, Subsidy, tax regulation mechanisms
UK	FiT, Quota system, Tax regulation mechanism

Table 3: Use of tendering and financing source of main RES support schemes

	Tendering:	**Financing (main part):**
Austria	No	**OFF budget**
Belgium	No	**OFF budget + budget**
Bulgaria	No	**OFF budget**
Croatia	No	**OFF budget**
Cyprus	**<u>YES</u>**	**OFF budget**
Czech Rep.	No	**OFF budget**
Denmark	**<u>YES</u>**	**OFF budget**
Estonia	No	**OFF budget**
Finland	No	**OFF budget**
France	**<u>YES</u>**	**OFF budget**
Germany	**<u>YES</u>**	**OFF budget**
Greece	No	**OFF budget**
Hungary	No	**OFF budget**
Ireland	No	**OFF budget**
Italy	**<u>YES</u>**	**OFF budget**
Latvia	No	**OFF budget**
Lithuania	No	**OFF budget**
Luxembourg	No	Budget
Malta	No	**OFF budget**
Netherlands	**<u>YES</u>**	Budget
Poland	No	**OFF budget**
Portugal	**<u>YES</u>**	**OFF budget**
Romania	No	**OFF budget**
Slovakia	No	**OFF budget**
Slovenia	**<u>YES</u>**	**OFF budget**
Spain	No	**OFF budget**
Sweden	No	**OFF budget**
UK	No	**OFF budget**

Table 4: Overview of identified grid connection issues and solutions (main barriers across the EU 27 in the connection phase)

Identified issues	**Possible solutions**
Long lead times & complex procedures	Identification of existing inefficiencies; Introduction of qualitative deadlines (e.g. "promptly"); Reduction of workload for public administration and/or grid operators; Harmonisation and simplification of grid connection requirements.
Lack of grid capacity / different pace of grid and RES-E development	Better coordination between grid & RES-E development; Collection of data on RES-E development from national registries and collection of data on development targets; Consideration of RES-E data in TYNDP1 and in all national plans.
Virtual saturation & Speculation	Definition of milestones in grid connection procedure; Introduction of grid reservation fees.
Lack of communication, and weak position of RES-E plant operator	Initialisation of exchange programs and communication platforms through projects at EU level; Encouraging stakeholders at MS level to participate in exchange programs and communication platforms, as well as to appoint contact persons.
Non-shallow costs	Process to define adequate distribution of costs at MS level to ensure investment security; Funding through EU budgets in case of interconnectors with European significance.

Table 5: Main barriers identified in each Member State in the connection phase:

Member State	**Main barriers to integration in the grid connection phase**
Austria	Distribution of costs Information policy regarding costs
Belgium	Missing obligation to connect RES-E installations, except in the framework of the "Inform & Fit" procedure. Connection can be denied due to insufficient capacities, no obligation to immediately reinforce grid to allow for connection
Bulgaria	TSO does not connect new renewable energy plants Capacity limits for renewable energy Advance payments
Cyprus	Bureaucracy, Lengthy Grid Connection Procedure
Czech Republic	Connection moratorium Supposed lack of grid capacity Speculation Envisaged advance payments
Denmark	No barriers detected
Estonia	Lack of sufficient grid capacity Speculation Testing for wind farms
Finland	Lack of grid capacity Distribution of costs Speculative grid applications

France	Costs of grid connection
Germany	Communication between stakeholders Lack of transparency Definition of technical and legal requirements
Great Britain	Planning consent Issues linked to the offshore transmission tender process Issues linked to the charging regime
Greece	Inefficient administrative procedures Insufficient special planning
Hungary	Status of the grid Capacity saturation and speculation Unstable policies for wind power
Ireland	Potential delays for grid connection due to the group processing approach Potentially higher shallow costs than in other Member States
Italy	Administrative barriers Overload of connection requests Virtual saturation
Latvia	Lack of sufficient grid capacity Speculation
Lithuania	Complicated connection procedure Legislation not clear High costs
Luxembourg	Definition of connection costs
Malta	Inefficient administrative procedures Insufficient special planning Competing public interest
Netherlands	Lack of sufficient grid capacity
Poland	Lack of sufficient grid capacity Complicated and not-transparent grid connection process Unclear regulations concerning the distribution of costs
Portugal	Complicated and slow licensing procedure related to the Environmental Impact Assessment
Romania	Virtual saturation Access to credit Information management
Slovakia	Delays during the connection process Speculation
Slovenia	Administrative procedures Long lead times Enforcement of RES-E producers' rights
Spain	Delays introduced by administrative procedures Heterogeneity of DSO technical requirements
Sweden	Cost bearing and sharing

Table 6: EU overview of RES-E balancing regimes

	Support scheme	Balancing responsibility	Exemptions for RES-E	Level of balancing responsiblity
Austria	FiT	no	-	0
Belgium	Quota	yes	yes	2
Bulgaria	FiT	no	-	0
Croatia	FIT/Other	no	-	0
Cyprus	Premium	no	- (planned)	0
Czech Republic	FiT / Premium	no	-	0
Denmark	Premium	yes	none	2
Estonia	Premium	yes	none	2
Finland	Premium	yes	none	2
France	FiT	no	-	0
Germany	FiT / Premium	Premium only	none	1
Great Britain	Quota, FiT	yes	for FiT	1
Greece	FiT	no	-	0
Hungary	FiT	yes	yes	1
Ireland/N. Ireland	FiT / (SEM?)	only for SEM	yes	1
Italy	FiT/Premium/Other	party	yes	1
Latvia	FiT (Premium planned)	yes	yes	1
Lithuania	FiT	no	-	0
Luxembourg	FiT	no	-	0
Malta	FiT	no	-	0
Netherlands	Premium	yes	none	2
Poland	Quota (FiT planned)	yes	none	2
Portugal	FiT	no	-	0
Romania	Quota	yes	yes	1
Slovakia	FiT	no	-	0
Slovenia	FiT/Premium	Premium only	none	1
Spain	FiT/Premium	yes	none	2
Sweden	Quota	yes	none	2

0: no balancing responsibility for RES-E; If there is no balancing responsibility, the column "Exemptions for RES" typically does not apply.

1: RES-E are not fully exempted, but there is a specific balancing regimes for RES-E or there is a balancing responsibility only under certain support schemes;

2: Full balancing responsibility for RES-E.

Source: European Commission

Table 7: Gate closure times before the delivery of electricity (April 2013)

Austria	15 min. before delivery
Belgium	60 min. before delivery
Bulgaria	Day-ahead (DA) notification
Cyprus	20h00 for DA
Croatia	14h00 for the DA market Intra-day (ID) starts at 15h00 2 hours before delivery
Czech Republic	60 min. before delivery
Denmark	12h00 for the DA market for the ID: 14h00 / trading takes place around the clock until 60 min. before delivery
Estonia	60 min. before delivery
Finland	60 min. before delivery
France	60 min. before delivery
Germany	15 min. before delivery
Greece	12h30 for DA market
Hungary	3 hours before delivery
Ireland	10h00 for DA
Italy	9h15 for the DA market → will soon change to 12h00 Gate closure time for the ID market 12h30
Latvia	60 min. before delivery
Lithuania	45 min. before delivery
Luxembourg	12h00 for DA market
Malta[38]	N.A.
Netherlands	60 min. before delivery
Norway	60 min. before delivery
Poland	60 min. before delivery (for wind)
Portugal	6 times during the day (2 ¼ hours ahead)
Romania	15h00 for the DA market
Slovakia	11h00 am for the DA market For ID market: 60 min. before delivery (6 per day) Balancing time: 13h30 pm
Slovenia	9h40 for the DA market ID market: trading phase from 11h00 until 60 min. before delivery balancing: 120 min. before delivery
Spain	12h00 for the DA market Gate closure time for the ID market: 6 times a day 17h45, 21h45, 1h45, 4h45, 8h45 and 12h45 15 min. before delivery for Renewable power
Sweden	60 min. before delivery

Source: OECD, EPEX, EEX, Nordpool, OTE, PXCE.

[38] The electricity supply market in Malta is not open to competition. Malta has been granted a derogation from the requirements of Article 32 and Article 33 of Directive 2009/72/EC-refer to Article 44 of the Directive. There is no wholesale market. There is one company, *Enemalta Corporation* that performs the activities of generation, distribution and supply of electricity to final customers. There is no transmission system. Any independent power producers may either consume the electricity produced on site or sell to *Enemalta Corporation* at feed-in tariff. Presently independent power production is limited to a number of small producers (generation capacity less than 200kW) generating electricity from RES.

Table 8: Grid connection distribution costs

Country	Grid connection distribution costs	Country	Grid connection distribution costs
Austria	Deep	Italy	Shallow
Belgium	Shallow	Latvia	Deep
Bulgaria	Deep	Lithuania	Deep (divided)
Croatia	Deep	Luxembourg	Deep
Cyprus	Shallow	Malta	Deep
Czech Republic	Deep	Netherlands	Shallow
Denmark	Shallow	Poland	Shallow?
Estonia	Deep	Portugal	Deep
Finland	Deep	Romania	Shallow
France	Shallow-deep	Slovakia	Deep
Germany	Shallow	Slovenia	Shallow cost principle
Greece	Shallow-deep	Spain	Deep (except small-scale RES)
Hungary	Shallow-deep	Sweden	Shallow
Ireland	Shallow	United Kingdom	Shallow

Table 9: Process for calculating support levels

Steps	Examples from the EU Member States
Cost base	Almost all Member States base support levels on project costs, except for those quota systems that are not technology-specific (e.g. Sweden/Norway, Poland). There are a few examples of non-cost-based parameters, e.g. Cyprus: compensation for communities, Croatia: bonus for contribution to the local economy. Most relevant cost parameters are taken into account. A broad range of additional cost parameters is explicitly included in some countries, e.g. in the Netherlands insurance and the costs of dismissing unwanted end products for manure digestion; in Bulgaria costs connected to a higher level of environment protection. This can make a comparison of support levels difficult. The same applies to different approaches for including network costs and market risk. Member states apply a variety of approaches for exposing RES-E plants to market integration and balancing costs (e.g. fixed balancing prices in Latvia and Denmark, percentage of market prices in Spain, bounded balancing prices in Belgium). There are also different approaches to including market integration costs in the support level (e.g. explicit management premium in Germany, inclusion of market risk in the cost base via the RoR and the assumed financing structure in Finland).
Expected generation	Locational differentiation is not applied in all Member States to promote the most cost-efficient location from the natural resources perspective (e.g. Latvia). In some cases there is an explicit

	decision to support only the most efficient locations (e.g. Italy, Austria).
LCOE calculation methodology	Calculation of LCOE is standard. Many Member States apply cash-flow models. Overall, differences in setting cost parameters are more critical than calculation method.
Process for setting individual cost parameters	Most Member States carry out cost studies, but there is a broad variety of different processes for specifying the cost parameters, e.g. in terms of stakeholder consultations, independent reviews, sensitivity analysis. There are also differences regarding the sources used (e.g. data from existing projects, price information from technology suppliers, comprehensive market surveys, international data and process to adapt it to the national context). There are also different levels of transparency of these cost studies.
Other support instruments	Most Member States either rely on a single instrument or take into account additional support measures when establishing the level of support, for example when setting the cost base (e.g. Netherlands) or when defining the support period (e.g. in Hungary).
Revenue projections	Premium schemes like the ones, for example, in Finland, Germany and the Netherlands allow for an ex-post revenue calculation. In some countries, future revenue levels are established by extrapolation from today's prices (e.g. Latvia, Romania). In other countries, revenue projections are based on detailed modelling of future market prices (e.g. UK, Spain). The market revenue is partly based on technology-specific profiles (e.g. Netherlands, Germany), partly the technology is not taken into account (e.g. Finland)
Process for transferring LCOE into the support scheme	Quota schemes, e.g. in the UK: The buyout price is defined ex-ante, but there is a significant influence of recycling mechanisms and supplier expectation on the support level. This effect on the actual support level is difficult to assess ex-ante. Premium schemes, e.g. in Spain: The actual premium is influenced by cap and floor and market price development. This is intended, but the actual effect on the support level is difficult to estimate ex ante.
Process for revising support levels	Most Member States review support levels on a regular basis. The process for adapting support levels to cost developments is **not always defined ex-ante. Automatic adjustment procedures are not standard.**

7 APPENDIX II

Further details for simple and transparent administrative procedures:

Given how the regulatory environment can impose major uncertainties on project development and investments, and therefore increase costs, it is important that these too are addressed.

Administrative costs can make up a big part of the actual cost for investing in renewable energies. Different national support levels reflect this. An EU-wide alignment of the technology costs and the other costs elements used for tariff calculation will create pressure on the various national administrations to become more efficient. This will in turn make support schemes themselves more cost efficient.

One-stop-shops or equivalent streamlined administrative procedures seem to be very effective measures. This should be coupled with clear administrative rules for awarding support, including pre-set time limits for permitting procedures.

The European Commission has the legal obligation to monitor the implementation of the Renewable Energy Directive 2009/28/EC which includes elements of good administrative practice. There are indications that a number of countries are still not fully complying and could streamline more their procedures. These include lengthy administrative procedures, such as permitting, that influence the effectiveness of national support schemes and ultimately make Member States reaching their targets more costly as it increases the support levels necessary to incite investments.

In parallel, the potentially differing national technical specifications and subsequent rules for equipment operation are also being standardised. From a European perspective it is an economic wastage to have so many parallel national systems that push up the costs for operators and manufacturers and prevent in cases market entrance.

Table 10: Assessment of the administrative procedures in the Member States

Member State	"One Stop Shop"?	One permit? (Nr. of permits?)	Online application for permit?	Max time limit for procedures?	Automatic permission?	Facilitated procedure for small-scale?	Identification of geographic sites?	Automatic entry into financial support scheme?	Overall assessment
Austria	Yes	No (?)	No	No	No	Yes	No	No	☹
Belgium	No	No (4)	n.a.	Partly (6 mths – 1 yr)	No	No	n.a.	n.a.	☹
Flanders	No	Partly (2)	n.a.	Yes (15 days - 4 mths)	No	Yes	Yes	No	😐
Walloon Region	No	Partly (2)	n.a.	Yes (90-140 days)	No	Yes	Yes	No	😐
Brussels	Yes	Partly (2)	n.a.	Yes (20-450 days)	No	Yes	n.a.	n.a.	😐
Bulgaria	No	No (?)	No	No	No	Yes	Yes	Yes	☹
Czech Republic	No	No (3)	n.a.	Yes (60 days – 72 mths)	No	Yes	No	n.a.	☹
Cyprus	Yes	No (5)	No	Yes (2-3 months)	n.a.	Yes	Yes	n.a.	😐
Denmark	Yes	Yes	n.a.	No	n.a.	Yes	n.a.	Yes	😐
Estonia	No	No (2)	No	No	No	No	Yes	No	☹
Finland	No	No (3)	n.a.	n.a.	n.a.	Yes	Yes	n.a.	☹
France	No	No (3)	Partly	Partly (?-1 yr)	No	Yes	n.a.	No	☹
Germany	Partly	Partly (2)	Partly	Partly (?-10 months)	n.a.	Yes	Yes	Yes	😐
Greece	Yes	No (3)	No	Yes (n.a.)	n.a.	Yes	n.a.	n.a.	☹
Hungary	Yes	Partly	Partly	Yes (n.a.)	n.a.	Yes	n.a.	No	😐
Ireland	No	No (2)	No	Partly (6 – 8 weeks)	n.a.	Yes	Yes	No	☹
Italy	Yes	Yes	No	Yes (30-90/180 days)	Partly	Yes	n.a.	No	😐
Latvia	No	No (8)	No	Partly (30 - 180 days)	n.a.	n.a.	n.a.	No	☹
Lithuania	Partly	No (2)	n.a.	Partly (10-30 days)	Partly	Yes	n.a.	No	☹
Luxembourg	No	No (2)	n.a.	Partly (3-5,5 months)	n.a.	Yes	n.a.	n.a.	☹
Malta	No	Partly	No	Partly (4 weeks)	n.a.	Yes	n.a.	No	☹
The Netherlands	Yes	Yes	Yes	Partly (6 months)	n.a.	Yes	Yes	No	😐
Poland	No	No (4)	No	Partly (30-65 days)	Partly	Yes	n.a.	n.a.	☹
Portugal	Yes	Partly (2)	Partly	Yes (120-250 days + 30 days for connection)	n.a.	Yes	Yes	n.a.	😐
Romania	No	No (7)	n.a.	Partly (30 days)	n.a.	No	n.a.	No	☹
Slovakia	No	No (3)	No	Partly (n.a.)	n.a.	Yes	Yes	n.a.	☹
Slovenia	No	No (>5)	n.a.	No	No	Yes	n.a.	n.a.	☹
Spain	No	No (>5)	n.a.	Yes (3 mths)	Yes	Partly	n.a.	No	☹
Sweden	Partly	Partly (2)	Partly	Partly (n.a.)	n.a.	Yes	Yes	No	😐
UK	No	No (3)	n.a.	Partly (1 yr)	n.a.	Yes	Partly	No	☹

(*Source: Renewable energy progress and biofuel sustainability, European Commission 2013)*