

Report D6.1, March 2016

Identification of alternative policy options to auctions for RES-E support

Mid-term report of Task 6.1



HORIZON 2020



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Identification of alternative policy options to auctions for RES-E support

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1 Introduction

The aim of this report is to identify non-auction policy instruments or design elements that share some or all of the same policy goals as auctions and to enable comparison between auction and non-auction policy options. The policy goals in question include static efficiency (i.e. improving cost-effectiveness), increasing market integration and cost and volume control of total support payments.

The report extends the framework established in report D2.2 to a consideration of non-auction policies. Taking outputs of WP2 and the considerable literature on RES support as a starting point, promising non-auction policy alternatives (instruments such as feed-in tariffs, feed-in premiums and tradable green certificates, among others, and the design elements within those instruments) are identified. The pros and cons of the alternatives with respect to the assessment criteria considered in WP1 are assessed. This will provide policy makers with insight on the comparison of auctions and alternative policy formulations.

The methodology used in this report is qualitative. It is based on a review of the theoretical and empirical literature on RES-E support schemes, which has provided useful information on the functioning of those schemes (see report D2.2 for further details). The starting assumption is that the success of RES-E support policies depends both on the choice of instruments and also on the design elements of these instruments. More specifically, the design of the support scheme is one, if not the key, pre-requisite for stable investment conditions (and the cost of capital) (Noothout et al 2016) and directly affects the remuneration level (revenues) for RES-E investments. In turn, they influence several of the aforementioned goals, including static efficiency, support costs and volume control (effectiveness). For example, different instruments and design elements influence different types of risks: the price risk due to varying market prices, the volume risk due to forecasting and marketing of the generated electricity, and cost risks because of the penalties (Noothout et al 2016).

Member States have a large margin of discretion to design their support schemes (EC 2014). In the context of this project, the choice of those instruments and design elements is inspired by an initial condition: they have to share at least one of the aforementioned goals of auctions. These goals have been put forward by national and EU policy makers in policy documents. Comments from Member States to the Commission's Green Paper on "A 2030 framework for climate and energy policies" in the context of the public consultation launched on 27th March 2013 clearly show that those goals are important for MS policy makers¹.

Several recent communications from the European Commission provide recommendations to MS on the use of RES-E support instruments and, thus, allow us to infer the goals that the European Commission considers as important. For example, the European Commission Guidance for the Design of Renewables Support

¹ The documents related to the public consultation are publicly available at: http://ec.europa.eu/energy/consultations/20130702_green_paper_2030_en.htm Either the "government" itself or the Ministries (usually Energy or Environmental ones) have responded in 14 Member States, stating the "official position" of the country: Austria, Cyprus, Czech Republic, Denmark, Spain, U.K., France, Estonia, Finland, Poland, Lithuania, Portugal, Romania and Slovenia. Other documents from institutions in some MS have been taken into account from those countries without an official response, including the German Federal Environment Agency, the Royal Swedish Academy of Sciences, the Netherlands Environmental Assessment Agency, the Nordic Council.

Schemes published on November 5th 2013 (EC 2013) argues that RES-E support instruments should adjust support levels to the costs of renewable energy technologies. Costs to the consumers should be reduced and overcompensation and excessive demand for new installations should be avoided. Instruments should be market-based, mitigating the problem of asymmetric information and reducing the risks of regulatory instability for investors. The document explicitly argues in favour of tenders for RES, which can be used to allocate support under different instruments such as feed-in premiums, investment support or green certificates.

The Communication from the Commission on January 22nd 2014 on a policy framework for climate and energy in the period from 2020 to 2030 (EC 2014a) states that national support schemes need to be rationalised to become more coherent with the internal market, more cost-effective and provide greater legal certainty for investors. Subsidies for mature energy technologies, including those for renewable energy, should be phased out entirely in the 2020-2030 timeframe. Finally, the Guidelines on State aid for environmental protection and energy 2014-2020 (EC, 2014b) mention that market-based instruments, including competitive bidding processes but also feed in premiums (FIPs), should gradually replace existing renewable support schemes from 2015 onwards. Those instruments are expected to increase cost-effectiveness and mitigate the distortions on competition. In nearly all cases, competitive auctions will have to be implemented in order to provide support to all new installations from 2017 onwards.

Given the emphasis on static efficiency and cost containment in the documents outlined above, this report will primarily focus on these two areas. RES-E support, and particularly FITs, has undeniable lead to an increase of EU RES-E capacity until 2010. However, this has also resulted in substantial increases in support costs, which reached 0.3% of EU GDP in 2012 (Ragwitz 2013) (see also Section 2). On the other hand, it will also take into account the influence of non-auction instruments and design elements on market integration since this is both a goal of the EC and one of the alleged advantages of auctions². This report is structured as follows. The next section briefly describes the assessment criteria considered in WP1, which will be used in this report to evaluate the non-auction alternatives. Section 3 identifies alternative instruments to auctions and some of their potential design elements. These are assessed according to the different criteria in Section 4. Section 5 concludes.

2 Assessment criteria and context conditions

The success of the functioning of any RES-E support scheme can be judged against to several criteria. In this context, we adopt a “policy-maker” perspective. Table 1 describes the criteria considered here and provides relevant assessment indicators. A more detailed description of these criteria and the rationale used to define them is provided in the report on assessment criteria in task 2.2 of the AURES project (see del Río et al 2015a).

² As stated in EC (2013, p.22), “market integration is the only pathway to further increase renewables in the most cost effective manner”. The impact assessment of the EU State Guidelines on State Aid stress the “increase the volume of renewable electricity participating directly in the market and in balancing markets” as one key policy objective (EC 2014, p. 32)

Table 1: Description of the criteria and indicators

Criteria	Description	Indicators
Effectiveness	Degree to which auctions result in deployment of RES-E projects.	Realisation rate (%)
Static efficiency (cost-effectiveness).	Reaching the target at the lowest possible overall costs. An auction outcome is efficient if the bidders with the lowest generation costs are awarded. The relevant costs here include generation costs and transaction costs, whether private or public. The later are called administrative costs.	Total generation costs (system costs)(€, €/MWh) (Private) transaction costs (€) Administrative costs (€).
Dynamic efficiency	This refers to long-term technology effects, including impact on innovation, technology diversity, cost reductions over time...	Private R&D investments (€). Evolution of the share of different technologies over time (%) Evolution of the costs of the technologies over time (€/MWh).
Support costs	Impact on the level of support for different technologies (average and total). This is usually paid by electricity consumers.	Average support level per technology (net of generation costs)(€/MWh) Total support costs net of total generation costs (€).
Local impacts	Impact on several variables at the EU, national, regional and local levels. They can be environmental or socioeconomic, and include emissions of GHG and local pollutants, variations in fossil fuel energy dependence, employment effects, industry creation, regional development and export opportunities...	GHG emissions being reduced (additional to the ETS)(tonnes) Emissions of local pollutants reduced (tonnes). Reduction of fossil fuel imports: trade balance affected (avoided fossil fuel consumption from Green-X) Local content / Promotion of local industry Regional concentration of deployment (??) Additional Jobs in renewable sector (number).
Sociopolitical feasibility	Degree to which the design elements and the whole support scheme are socially acceptable and politically feasible. This depends on other criteria (minimization of	Fit to decision makers' institutional capacity

	support costs, the existence of positive and negative local impacts from RES-E deployment, etc...). A main aspect is whether the design element or support scheme fits in the existing institutional structure.	Qualitative variable (more/less acceptable; more/less politically feasible). "Revealed preference of (national) policy-makers for a specific design element"?
Legal feasibility	Extent to which a given design element or the whole support scheme comply with EU legislation (primary and secondary law), including State Aid rules and internal market principles.	Compliance with State Aid rules (Y/N) Compliance with internal market principles (Y/N).

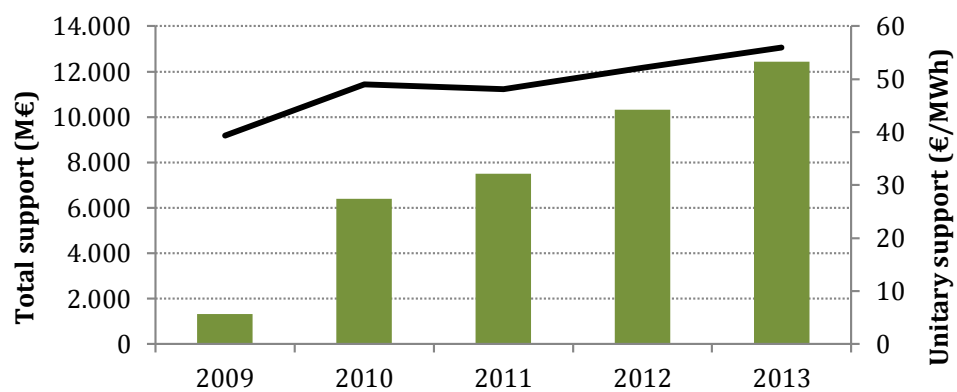
Given the emphasis accorded to them in the EU documents outlined in the previous section, this report focuses on common policy goals for RES-E support:

- Static efficiency – the ability of a policy to deliver renewable capacity at the lowest possible overall costs; and
- Cost containment – a related but distinct goal to cost, which often depends on the ability of a policy scheme to limit capacity growth, regardless of the unitary (€/MWh) cost; It refers to the support that is paid to RES-E generators and which usually falls on electricity consumers.
- Market integration – the compatibility of the policy with the principles of market integration, which may include electricity market exposure or balancing requirements

Note that static efficiency and cost-containment are not totally independent from each other. In fact, they are related by "investors' risks" which in turn is influenced by the type of RES-E support policy. An effective and cost-efficient RES-E policy is risk-conscious and does not introduce unnecessary policy-related risks. Low cost for loans and equity would reduce the cost of RES-E projects and the required financial support from governments or consumers, while more investments into RES-E projects can be attracted and more RES-E projects can be realized (i.e., the system becomes more effective). A country with RES-E policies leading to lower investors' risks will experience more RES-E growth at lower specific generation cost. Lower generation cost can be translated almost 1:1 to lower required support policy cost (Rathmann et al 2011). Both criteria also interact in more indirect ways. For example, large RES-E support costs may trigger social rejection, lead to retroactive changes which, in turn, increases the risk to invest in such a country and, thus, the costs of capital and the investment costs, leading to higher generation costs.

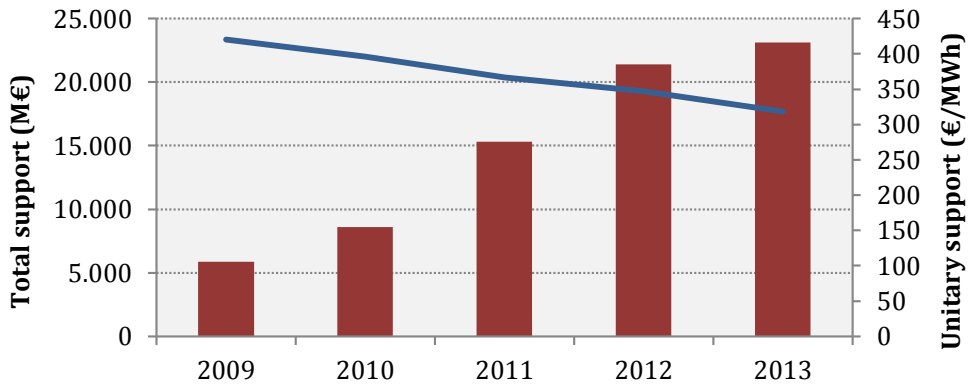
Support costs for wind energy and solar PV in the EU increased almost ten-fold and four-fold, respectively, between 2009 and 2013 (figures 1 and 2). In 2013, the total support costs were, respectively 12.4 and 23.1 thousand million euros. However, whereas unitary support for wind increased during the period, it went down for solar PV. Nevertheless, unitary support for solar PV was still orders of magnitude higher than for wind on-shore.

Figure 1. Evolution of total and unitary support for wind energy in the EU in the period 2009-2013



Source: CEER, 2011, 2013 and 2015. Columns refer to total support (M€), the line refers to unitary support (€/MWh).

Figure 2. Evolution of total and unitary support for solar PV in the EU in the period 2009-2013



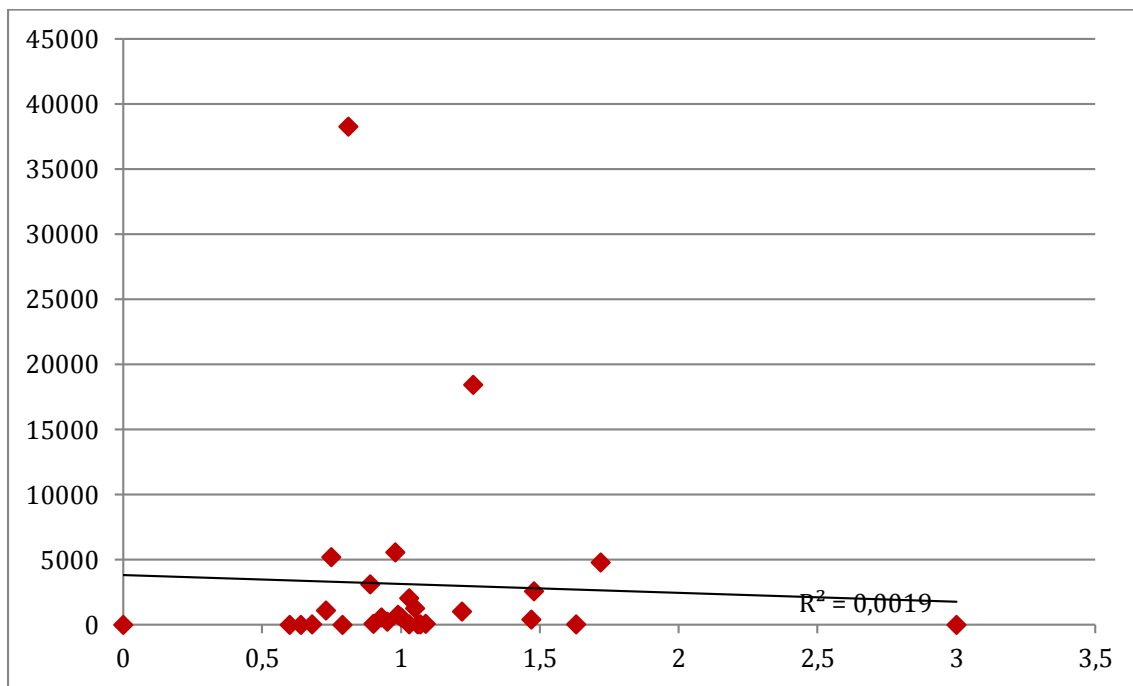
Source: CEER, 2011, 2013 and 2015. Columns refer to total support (M€), the line refers to unitary support (€/MWh).

Regarding static efficiency, i.e., whether the costs of generation from solar PV and wind energy are minimized, publicly available data on system costs at the EU level are not available. However, an analysis in terms of allocative efficiency can be performed. A plant can be built in places with better or worse renewable resources (wind or solar radiation). If it is built in the best places, then electricity generation from a MW of installed capacity is maximized. Regarding solar PV, an EU-wide look suggests that this has not been the case in Europe. Maps of the solar irradiation in Europe suggest that the best solar potentials are in Southern European countries. However, this is not where solar PV plants have mostly been located (Mir-Artigues and del Río, 2016).

Figure 3 plots the cumulative solar PV capacity deployed in the EU Member States as of 2014 (MWp, y-axis) against the amount of generation (GWh) per MW of installed capacity. If wind farms were deployed where it was efficient to do so, then many points in the figure (which refer to specific countries) would have been located in the top left region in the figure. This does not seem to have been the case. Those countries where solar PV has been installed the most are not those with the highest generation per MWp installed, suggesting that the allocative efficiency of solar PV support in the EU has not been high (correlation coefficient: 0.0019).

Figure 3. Solar PV installed capacity in the EU Member States (MWp, y-axis) versus the amount of generation per MW installed (GWh/MWp, x-axis) (2014)

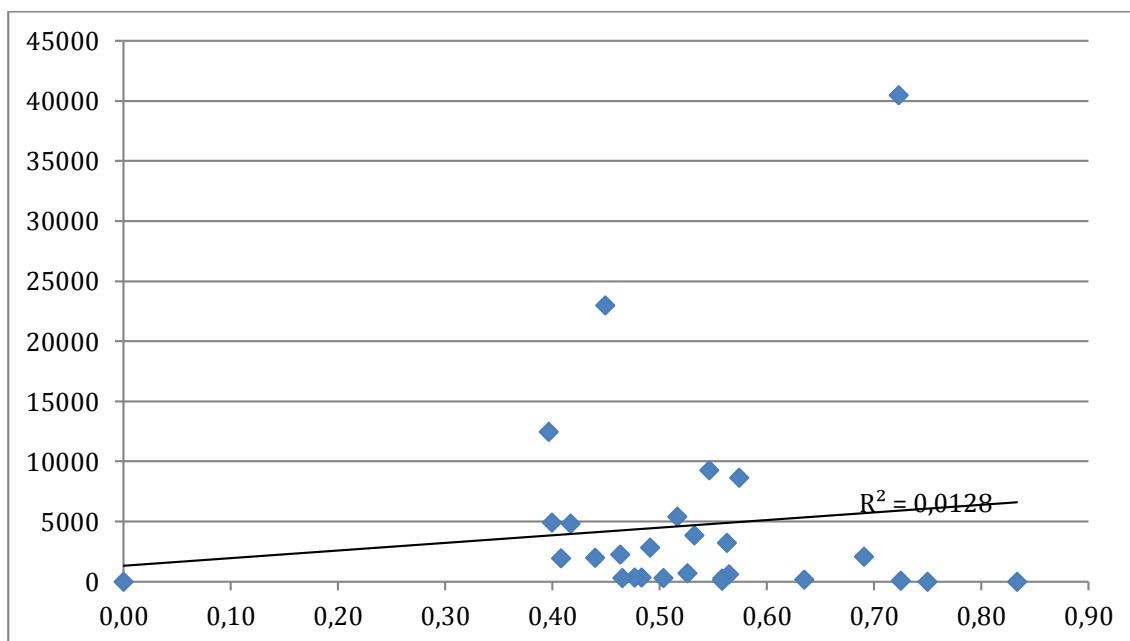
Source: Own elaboration from Eurobserv'er (2015a).



A similar although slightly better picture can be observed in figure 4 for the case of wind (correlation coefficient: 0.012).

Figure 4. Wind energy installed capacity in the EU Member States (MW, y-axis) versus the amount of generation per MW installed (GWh/MW, x-axis) (2014)

Source: Own elaboration from Eurobserv'er (2015a).



Obviously, apart from solar PV policy, there might be some reasons why solar PV plants or wind farms could or should not be installed in the places with the best solar resources, but these reasons bring a cost in terms of a loss in allocative efficiency. One of these reasons is related to willingness-to-pay for a clean and non-fossil fuel energy source. Another is that if solar resources are concentrated in only a few locations, this might raise grid integration issues. Furthermore, people might be opposed to the deployment of ground-mounted solar PV panels near their houses, leading to a NIMBY effect. These data should be taken with caution, however, since the amount of MW installed in a country also depends to some extent on its extension and, thus, the above can only be considered as a rough indicator of allocative efficiency.

3 Non-auction policy instruments and design elements

3.1 Instruments

There is an abundant literature on RES-E support schemes (see Mitchell et al 2011, EC 2013, Held et al 2014, REN21 2015 for recent overviews). This literature has traditionally distinguished between primary and secondary support instruments.

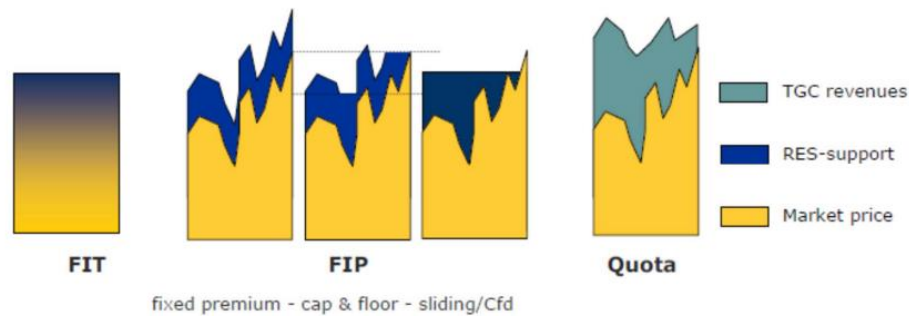
RES-E deployment promotion tended to be based on three main (primary) mechanisms, whose costs are usually borne by consumers: Feed-in laws, quotas with tradable green certificates (TGCs) and tendering. The classical distinction between primary and secondary instruments is a widespread one in the RES-E support literature, although with different names, “dominating instruments”, “main support schemes” and “primary” and “secondary” instruments. This distinction is made in order to differentiate instruments which are the basis (the main economic incentive) for RES-E support in some countries and those which are less significant. Most RES-E investments in EU countries have been triggered by feed-in laws or quotas with TGCs, whereas other instruments have played a minor role, with some exceptions.

- Feed-in laws provide for preferential prices per kWh (or MWh) of RES-E generated, paid in the form of guaranteed premium prices and combined with a purchase obligation by the utilities. Feed-in tariffs (FITs) provide total payments per kWh of electricity of renewable origin, whereas a payment per kWh on top of the electricity wholesale-market price is granted under feed-in premiums (FIPs).
- TGCs are certificates that can be sold in the market, allowing RES-E generators to obtain revenue. This is additional to the revenue from their sales of electricity fed into the grid. Therefore, RES-E generators benefit from two streams of revenue from two different markets: the market price of electricity plus the market price of TGCs multiplied by the number of MWh of renewable electricity fed into the grid. The issuing (supply) of TGCs takes place for every MWh of RES-E, while demand generally originates from an obligation, usually on electricity suppliers. Electricity distribution companies must surrender a number of TGCs as a share of their annual sales or pay a penalty. The TGC price covers the gap between the marginal cost of renewable electricity generation at the quota level and the price of electricity.

A major differentiator between these primary instruments is the relationship between total remuneration and market prices.

Figure 5: Relationship between remuneration and market prices for FITs, FIPs and quotas

Source: Ragwitz, 2012



- *Auctions.* The government invites RES-E generators to compete for either a certain financial budget or a certain RES-E generation capacity. Defined technologically neutral or within a given technology band, the cheapest bids per kWh are awarded contracts and receive the subsidy. The operator is paid the bid price or auction clearing price per kWh.

Several secondary instruments have been combined with the former in the past, including:

- *Investment subsidies.* They are granted in the beginning of the project lifetime and can be calculated as a percentage of the renewable energy output or the specific investment cost, although this latter version is more common. Investments grants for RES-E are available in many EU Member States (MS).
- *Soft loans* are usually provided by governments with a rate below the market interest rate. The low interest loans can be offered by the government directly through state-owned banks or through subsidies to commercial banks. In some cases, they can significantly reduce the costs of capital. Soft loans may also provide longer repayment periods or interest holidays. In short, they involve more favourable conditions for borrowers.
- *Fiscal incentives* can be exemptions or rebates on (energy, corporate or income) taxes, tax refunds, lower VAT rates or attractive depreciation schemes.
- *Green pricing/Green Funds.* Under this system, electricity consumers pay a surplus on their electricity bill for the promotion of electricity from RES. Therefore, this system is voluntary and based on a willingness to pay (WTP) for green electricity on the part of consumers (Uyterlinde *et al.*, 2003). The extra costs of RES-E generation are covered by the surplus, which is received by the generator. An independent organization guarantees that the electricity for which consumers pay a price has a renewable origin.

In contrast to primary instruments, which generally cover all RES-E installations and are set at the national level, secondary instruments are usually limited in scope and circumscribed to specific types of projects (e.g., small ones) and technologies (e.g., solar PV). Whereas main instruments are almost always applied at the national level, secondary ones are often applied at both the national and lower government levels, that is, regional/provincial/municipal.

This report will focus on the most commonly used primary non-auction instruments in the EU (EC 2013), including FITs, FIPs and quota obligations, although investment subsidies, fiscal incentives and soft loans will also be considered in the assessment of different options.

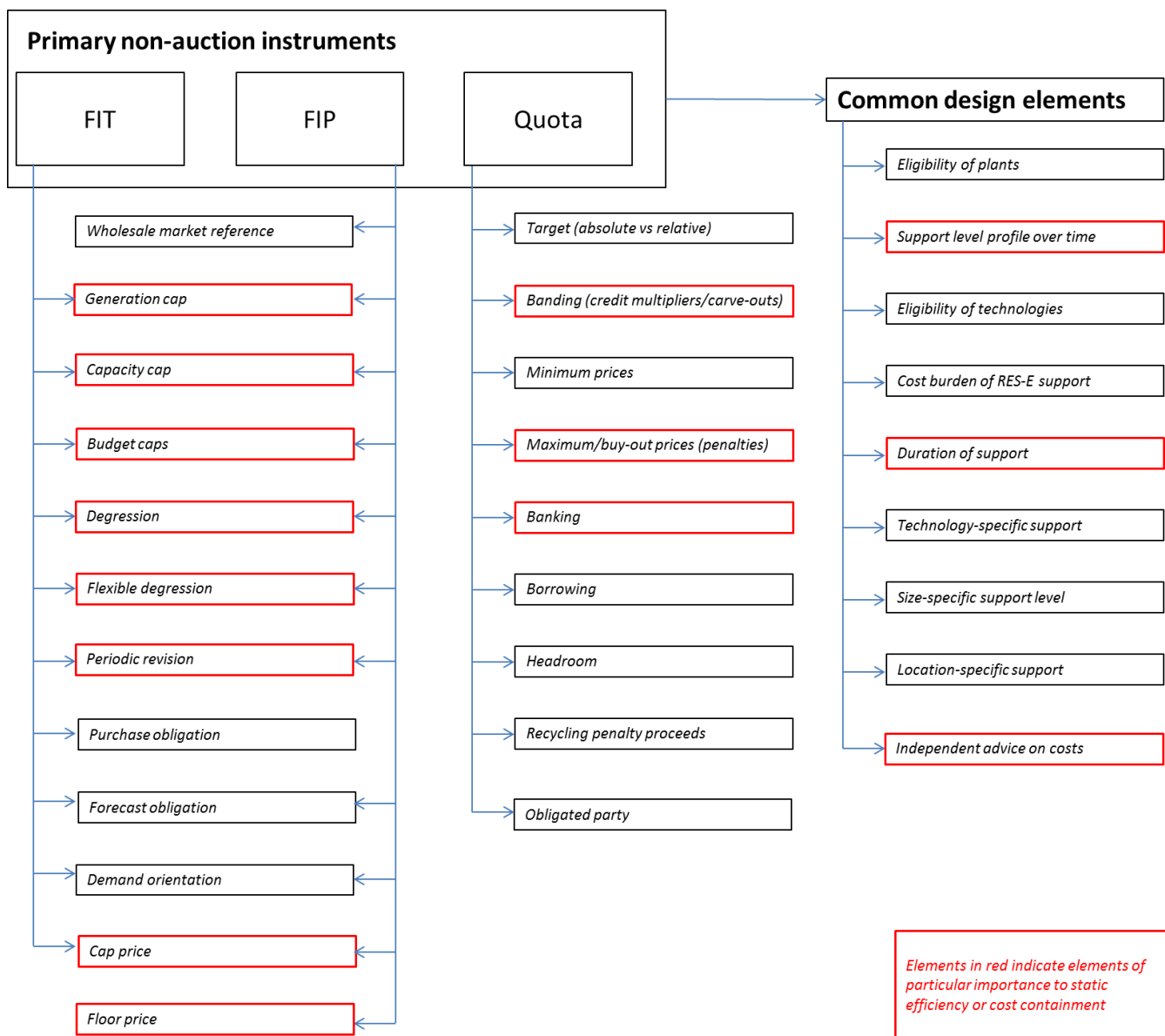
3.2 Design elements

In many ways, instrument-based classification has begun to outlive its usefulness. Several authors have pointed out that design elements are at least as relevant as support instruments when assessing RES support policies. Researchers have recently stressed that the 'devil lies in the details' and that the success or failure of instruments applied in the real world mostly depends on their design elements. The assertion is that intra-instrument differences may be as important as inter-instrument ones. This has been clearly shown in empirical analyses (see del Río et al 2012a, del Río 2008, Ragwitz et al 2007, IEA 2008). Recently, some efforts have been made to systematically classify those design elements. Fitch-Roy (2015), for example, identifies three functions that must be performed by a primary support scheme and effectively asks three questions vital to the design of the instrument:

- **Allocation** - how is the support allocated?
- **Remuneration model** - on what basis does the plant owner receive support?
- **Deciding the level** - how is the level of the remuneration determined?

del Río et al (2012a, 2015b), on the other hand, distinguish between different categories of design elements: common design elements, common design elements with instrument-specific implementation features and instrument-specific design elements. An analysis of both instrument and design elements is used here as the basis of comparison between auction and non-auction policies.

Figure 6: Primary non-auction design elements. Red outlines indicate elements of particular importance to static efficiency or cost containment



3.2.1 Common design elements

Some design elements can be common to different instruments, including auctions (see the Box 1 for a description). However, since the aim is to analyse those alternatives to auctions, these will not be considered in detail in this report.

Box 1: Common design elements

- **Eligibility of plants (new vs. existing).** Only new plants are eligible. The aim of support schemes is mainly to promote new capacity.
- **Constant or decreasing support level during support period.** Support for existing plants may be greater at the start of the period and be reduced over time (either an annual percentage reduction or a stepped reduction after some years) or support may be constant. Experience shows that investor's confidence increases when terms and conditions of this reduction are known beforehand.
- **Eligibility of technologies** (i.e. which technologies are included or excluded) is also an EU prerogative, as it is currently the case under the RES Directive (Directive 2009/28/EC (European Commission (2009))), where the eligible technologies are defined.
- **Cost burden of RES-E support.** The cost burden for RES-E support may fall on either electricity consumers or taxpayers (i.e. the public budget).
- The **duration of support** is a crucial element in all instruments. The specialised literature shows that long (but not over-long) duration periods of between 15 and 20 years provide low risks for investors and, thus, comply with the effectiveness and efficiency criteria (a low risk premium make projects more bankable and reduce the financial costs of the project).
- **Technology-specific support.** A similar support level might be provided for all technologies (regardless of their generation costs) or support could be modulated according to those costs. The manner in which support is provided to specific technologies is clearly very different under different support schemes. Thus, a more detailed discussion of this design element is provided under the heading "instrument-specific design elements".
- **Size-specific support level.** Support may be differentiated according to the size of the installation, taking into account that, generally, the generation costs (€/MWh) of larger installations are lower since they benefit from economies of scale; and governments may wish to promote small-scale installations for a number of reasons (decentralised generation and social acceptability).
- **Location-specific support.** Support levels might be modulated according to the location of the plant (e.g. built-in, stand-alone), with greater support levels provided for plants deployed in places with greater costs or less abundant

resources. At first, this may seem at odds with economic efficiency, since installations would not be promoted where generation costs are minimised. However, a support level which is not differentiated per location could lead to excessive rents for the owners of plants in places with very good resource conditions. All in all, this disincentive may be eliminated by making the differential support (support levels minus generation costs) still greater at places with the best renewable resource. The rationale behind location-specific support is to avoid concentration of renewable energy projects in a few locations.

Source: del Río et al (2012, 2015b).

3.2.2 Common design elements with instrument-specific features

Some of the aforementioned common design elements may take different forms under different support schemes. Table 2 below shows these commonalities and differences. Some of these instrument-specific design elements might be relevant for our analysis. Some of the implications of the choices for the main criteria considered in this report (static efficiency, increasing market integration and cost and volume control of total support payments) and for the rest of assessment criteria will be discussed in this section.

Table 2 Common design elements under non-auction instruments (with instrument-specific features)

Source: Adapted from del Río et al. (2012a)

Design element	FIT	FIP	TGC
Profile of support over time (constant or decreasing support level during support period)	FIT level constant during the duration of the support or “front loading”, i.e. reductions of FIT over time	FIP level or sum of FIP + electricity price (in case of sliding premium) constant during the duration of the support or “front loading”, i.e. reductions of FIP over time.	Constant support over time or more TGC per MWh generated in the first years of operation or for a fixed quantity of generation, and less TGC/MWh thereafter or equal number of TGCs per MWh generated over time.
Technology-specific Support	FIT is differentiated across technologies to reflect technology-specific generation costs. The alternative is to have a uniform fixed tariff for all technologies	FIP is differentiated across technologies to reflect technology-specific generation costs. The alternative is to have a uniform premium for all technologies	Banding can be implemented through carve-outs or through credit multipliers (see text). The alternative is no use of carve-outs or credit multipliers.
Size-specific support level.	FIT level modulated according to the plant size. Smaller FIT for large-scale and higher	FIP level modulated according to the plant size. Smaller premiums for large-scale and higher premiums for small-scale plants.	Small-scale installations receive more TGCs than large-scale installations

	tariffs for small-scale plants. Only installations below a certain capacity threshold would receive the support (stepped FIT)	Only installations below a certain capacity threshold would receive the support	Only installations below a certain capacity threshold are eligible to receive TGCs
Location-specific support level	FIT level modulated according to the location of the plant (stepped FIT)	FIP level modulated according to the location of the plant.	Different number of TGC according to the location of the plant.

Broadly speaking, there are two large categories of common design elements with instrument-specific features: the profile of support over time and diversity. Regarding the former, support can be constant over time (i.e., the same amount of support in terms of €/MWh in year 1 and in year n) or decreasing over time until the end of the support period. Assuming that the same support is provided during the whole period, a greater amount of support initially would lead to better financing conditions for the investor, which would make their projects more bankable, probably reducing its financing costs. This would result in a reduction of generation costs and, thus, a greater level of static efficiency. Although the amount of policy costs has been considered constant by assumption, it could be expected that a lower generation cost would be translated into a lower unitary support cost level. However, providing more support up-front may lead to an incentive to generate more at the start of the period, when the remuneration is higher. This may lead to a lower ability to control volumes over time than in the case when support is constant over time. No significant impact on market integration can be discerned. The greater incentive to generate more electricity in the initial years may provide a push to have equipment which is more efficient in those initial years, but the extent to which this is feasible for manufacturers is unclear. Providing greater support level initially may be less politically feasible, since the short-term promotion costs are greater and more visible for electricity consumers, which may be a less attractive option for policy-makers. What it is very clear is that differentiating support over time is quite easy to do under FITs and FIPs. In fact, this has been done in the past (e.g., Spain since 2004). It can be done under quotas with TGCs, but it would require a complex long-term adaptation of the interim targets.

Regarding the issue of diversity, this may come in different manners: technological, actors', size or geographical diversity. There might be reasons to differentiate support according to technologies, size or location, providing greater support for smaller plants or to encourage the deployment in places with a worse solar resource potential (to facilitate the access to RES-E by small actors, to have a less geographically concentrated deployment of RES-E etc.)(del Río et al 2012b). There are several reasons why governments may be interested in having diversity (see report D2.2 of the AURES project, del Río et al 2015b). Here we will just comment briefly on how the different alternatives for diversity can be promoted under different non-auction instruments and the implications of different alternatives for different assessment criteria.

Support may be technology-neutral or technology-specific in any of the four instruments considered (FIT, FIP, TGCs and auctions). Under FITs and FIPs, support can be differentiated across technologies to reflect technology-specific generation costs (stepped FITs or FIPs). The alternative is to have a uniform fixed tariff for all technologies. In quotas with TGCs, technology'-specific support can be implemented in the form of banding. In turn, banding can be implemented through carve-outs or through credit multipliers. Under carve-outs, targets

for different technologies exist, leading to a fragmentation of the TGC market, with one quota for the mature and another for the non-mature technologies. Under credit multipliers, more TGCs are granted per unit of MWh generated for immature technologies compared to mature technologies. The alternative (technological neutrality, uniform support) is no use of carve-outs or credit multipliers.

Under all instruments and design elements considered, neutrality in diversity (whether technological, actors', size or geographical) would generally lead to a greater level of allocative efficiency. In the case of technological neutrality, the cheapest (and most mature) technologies would be promoted and, thus, the lowest short-term costs would be attained. However, this would result in excessive remuneration levels for those technologies (negatively affecting support costs) and the exclusion of more expensive, still maturing technologies (negatively affecting dynamic efficiency). The impact of different alternatives on market integration is uncertain, and would not depend on the influence on mature / less mature technologies but on whether intermittent or non-intermittent technologies are affected.

Size and actors' diversity are somehow related (small/large projects/developers). Size-specific support levels may be implemented in different ways depending on the instrument. Under FITs or FIPs, the remuneration level can be modulated according to the plant size, granting lower FITs for large-scale and higher tariffs for small-scale plants. In quotas with TGC schemes, small-scale installations could receive more TGCs than large-scale plants (for each MWh of electricity generated) or only plants below a certain capacity threshold are eligible to receive TGCs. Having different sizes (instead of large ones) would reduce the benefits of economies of scale in production. However, it is indirectly a way to discourage the smaller developers, which may not be desired (see del Río et al 2015b). Size restrictions can have a considerable impact on volume and cost control under FITs (in the absence of generation, budget or capacity caps). However, the direction of the effect is uncertain. On the one hand, many small PV plants may result in a size-restricted FITs, which may lead to an uncontrolled increase in capacity (in case this is not restricted by another design element). On the other hand, large plants may lead to large amounts of electricity generation, profiting from the aforementioned economies of scale.

Finally, location-specific support can be provided under FITs and FIPs by modulating the support levels according to the location of the plant (stepped FITs or FIPs). In quotas with TGCs, a different number of TGCs can be provided according to the location of the plant (or pre-specified locations may be defined). It is genuinely more feasible to differentiate support according to the location in FITs and FIPs. In fact, stepped FITs have been implemented in a number of countries for many years (see Ragwitz et al 2007). Apart from the general impacts on static efficiency and volume and cost control mentioned above, other aspects should be added to the analysis. Providing location-specific support may reduce grid congestion in certain locations (which would lead to a reduction in system costs and, thus, a greater level of static efficiency). On the other hand, a greater concentration in certain locations may lead to NIMBY effects and, thus, make the granting of administrative authorisations more difficult, which would negatively affect effectiveness (volume control), static efficiency (greater project development costs) and, possibly, support costs (requiring more support to ensure a given profitability level).

In general, FITs and FIPs have been more successful in promoting diversity (any type) in the past compared to TGC schemes, even with banding (Mitchell et al 2011).

3.2.3 Instrument-specific design elements

Finally, instruments have different design elements which are rather specific to the instrument. This section provides a list of relevant design elements of FITs, FIPs and TGCs. Their influence on different relevant criteria are analysed in section 4.2.

3.2.3.1 FITs and FIPs

FITs and FIPs have some common design elements, whereas others are FIT or FIP specific. Table 3 (below) provides a description of the main design elements in FITs/FIPs. The purchase obligation has usually been stressed as a defining feature of FITs. However, it can also be implemented in auctions. Therefore, since it is not a defining characteristic of non-auction instruments with respect to auction, it will not be analysed in section 4.

Table 3: FIT and FIP design elements Source: Adapted from del Río et al. (2012a)

Design element /alternative	Description
Support tied / not tied to electricity price	Support may or may not be linked to the electricity price. For example, in Spain between 2004 and 2007 RES-E support was set as a percentage of the electricity price (reference average tariff).
Support level adjustment methods and cost-containment mechanisms (new plants)	Some elements may help to control costs: <ul style="list-style-type: none"> • limits on generation eligible for support, • capacity limits, • budget caps. • Traditional degression. • Flexible degression. • Periodic revisions.
Purchase obligation (FIT)	Obligation imposed on grid operators or suppliers to purchase green electricity.
Forecast obligation (FIT only)	This design element is particularly suitable for fluctuating RES
Demand orientation	higher support level for RES-E fed during periods of peak demand for electricity.
Cap price (only FIP)	Support is capped (electricity price + premium)
Floor price (only FIP)	A floor ensures a minimum support level (electricity price + premium).

Within FIPs, a main distinction is between fixed (“ex ante”) FIPs and sliding (“ex post”) FiPs. Fixed FiPs are set once and do not alter. The total remuneration thus depends on the market prices. A specific technology (eg. PV systems) competes with all other generating technologies on wholesale markets. Their total remuneration is therefore more uncertain, which raises investors’ risk and ultimately increases the cost of

capital and LCOE. However cap and floor remuneration levels (which apply to the addition of the fixed FiP and the electricity price) may limit the volatility of support for the investor.

Sliding FiPs are set at regular intervals, typically months, to fill the gap between the average market price perceived by all generators of a given technology and a pre-determined strike price. The United Kingdom's "contract for difference" can be considered as a sliding FiP. With sliding FiPs, PV systems (for example) would compete with one another. Those performing better than average in delivering power when the electricity prices are high get higher returns. Those performing worse than average get lower returns. The difference in returns is more modest than with ex ante FiPs, and the increases in risk and costs of capital are less pronounced. Since RES-E capacity has increased the most with FIT schemes (Ragwitz 2012), cost concerns have mostly been a major issue and, thus, cost-containment mechanisms are particularly relevant for this type of instrument. A main cost-containment mechanism are caps. Often caps are technology-specific and specify a maximum budget or capacity to be built or committed in a given period. In some systems projects receive support on a first-come first-serve basis. In other systems projects have to apply before a fixed date and are chosen randomly in case of demand being higher than the cap – a "gamble" from the project developer's perspective (Rathmann et al 2011). Obviously, the capacity under the cap can also be allocated through auctions.

Table 4 describes some of these cost-containment mechanisms. Their pros and cons are discussed later in the text.

Table 4: Description of cost-containment mechanisms

Mechanism	Description
Capacity caps	The amount of capacity installed in a given period is limited.
Generation cap	Maximum number of full-load hours supported
Periodic revisions	Support levels are revised (for new plants) periodically
Total budget cap	Maximum amount of total financial support for a given period
Traditional degression	Degression refers to reductions over time in support levels for new plants. Degression rates are applied to new capacities in a given year. Degression rates refer to the percentage reduction of support per year. Under traditional degression, a pre-set reduction of support levels applies over time for new plants (i.e, constant degression rate over time).
Flexible degression	The reduction in support levels over time depends on the total installed capacity in a previous period (year, quarter or month). Thus, the degression rate is endogenous to capacity installed at t-1.

According to Mitchell et al (2011), the most effective and efficient FITs have included most or all of the following elements:

- Utility purchase obligation;
- Priority access and dispatch;
- Tariffs based on cost of generation and differentiated by technology type and project size, with carefully calculated starting values;
- Regular long-term design evaluations and short-term payment level adjustments, with incremental adjustments built into law in order to reflect changes in technologies and the marketplace, to encourage innovation and technological change, and to control costs;

- Tariffs for all potential generators, including utilities;
- Tariffs guaranteed for a long enough time period to ensure adequate rate of return;
- Integration of costs into the rate base and shared equally across country or region;
- Clear connection standards and procedures to allocate costs for transmission and distribution;
- Streamlined administrative and application processes; and
- Attention to preferred exempted groups, for example, major users on competitiveness grounds or low-income and other vulnerable customers.

3.2.3.2 Quotas with TGC schemes

Table 5 provides a description of the main design elements in quotas with TGC schemes. Critical in the effectiveness of quotas with TGCs seem to be well-designed policies with long-term contracts. It is possible for a quota system to achieve a high rate of RES-E investment if the quota is high enough and backed by credible policies and legal requirements (Mitchell et al 2011). Obligation levels need to be set well in advance and the quota obligation should be guaranteed to be in place for a sufficiently long time period in the future in order to guarantee future demand for RES. For the same reason penalties should be set well in advance, significantly above green certificate prices, and enforcement of the quota obligation should be guaranteed (Rathmann et al 2011). According to Mitchell et al (2011), the most effective and efficient quota schemes have included most if not all of the following elements, particularly those that minimize risk:

- Application to a large segment of the market.
- Clearly defined eligibility rules including eligible resources and actors.
- Well-balanced supply-demand conditions with a clear focus on new capacities—quotas should exceed existing supply but be achievable at reasonable cost.
- Long-term contracts/specific purchase obligations and end dates, and no time gaps between one quota and the next.
- Adequate penalties for non-compliance, and adequate enforcement (applies to quotas and tendering/bidding).
- Long-term targets, of at least 10 years. □ Technology-specific bands or carve-outs to provide differentiated support.
- Minimum payments to enable adequate return and financing.

Table 5: Design elements in TGC schemes Source: Adapted from del Río et al. (2012a)

Design element /alternative	Description
Target (absolute / relative)	Under a quota with TGCs, the RES-E target may be set in either relative terms (as a percentage of electricity demand) or in absolute quantities (in TWh).
Banding	Banding can be implemented through carve-outs or through credit multipliers (see table 2 and section 3.2.2)
Minimum prices	Minimum TGC prices guaranteed to ensure a minimum level of revenue to the investors.

Maximum TGC prices (penalties)	An appropriate penalty is set above the marginal costs of the marginal technology which sets the TGC price.
Banking	Banking refers to the possibility to use TGCs issued in one specific year to comply with RES-E targets in a future year.
Borrowing	Borrowing refers to the possibility to use the TGCs to be issued in a future year to comply with RES-E targets in a previous year.
Guaranteed headroom	This measure was introduced in 2009 in the U.K. RO. It was aimed at addressing the ROC price “cliff edge” problem. Instead of an annual target, the obligation for a period is set at a level based on expected renewable generation plus a further proportion (an additional 8%, or 10% from April 2011) of the ROCs expected to be issued in the relevant period (Woodman and Mitchell 2011).
Destination of the proceeds from the penalty	The proceeds from the penalty may be redistributed to the suppliers who have fulfilled their quota or to cover administrative costs.
Obligated party	Either electricity suppliers or generators.

3.2.4 Relevant non-auction schemes aimed at static efficiency and cost-containment

Focusing the previous literature on the non-auction alternatives which may result in two key goals (or criteria according to section 2) of auctions (static efficiency and cost-containment), the following options have been chosen from the above set. First, instruments considered in the analysis performed in this report include all the primary and secondary instruments. Regarding the design elements, the following table includes the ones which are considered for the main (primary) instruments.

Table 6: Non-auction alternatives considered for cost-containment and/or improvements in static efficiency (design elements).

Quotas with TGCs.	FITs	FIPs
Cap prices	Support tied /not tied to electricity prices	Support tied /not tied to electricity prices
Floor price	Demand-orientation	Demand-orientation
Banding: credit multipliers	Forecast obligation	Generation cap
Banding: carve-outs	Generation cap	Capacity cap
Banking	Capacity cap	Budget cap
	Budget cap	Traditional degression
	Traditional degression	Flexible degression
	Flexible degression	Cap prices (sliding premium, CfDs)
	Periodic revisions	Floor prices
		Periodic revisions

4 Assessing relevant non-auction schemes aimed at static efficiency and cost-containment

In this section we discuss both non-auction instruments and design elements for primary instruments intended to achieve static efficiency and cost containment.

4.1 Non-auction instruments

As discussed earlier, the focus of this report is on the assessment of non-auction policies with respect to the goals of cost containment and improving static efficiency. However, other criteria may also be relevant and are introduced where appropriate.

The discussion in this section aims to identify and assess the “base cases”, i.e., the instruments in an abstract setting before modification through the use of design elements which are included in the following section. This section discusses the pros and cons of different alternatives with respect to those criteria, and summarises them in a table.

4.1.1 FITs without cost-containment mechanisms

FITs, whereby support levels are administratively set, have traditionally been identified as problematic in terms of static efficiency and cost-containment. For example, the impact assessment accompanying the document Communication from the Commission Guidelines on State aid for environmental protection and energy for 2014-2020 states that “administratively established support levels do not ensure cost-efficiency due to the information asymmetries between the regulator establishing the support level and the producers that benefit” (EC 2014, p.18).

It is argued that FITs do not provide incentives for the choice of the cheapest technologies or locations (Borenstein 2011). While this might be the case, it does not necessarily have to be so if appropriate design elements are adopted (see next subsection). In addition, the incentive to choose the best locations in terms of renewable resource potentials is not lost, since it may mean greater profits for project developers (except, possibly, under a stepped FIT). Regarding support costs, they have led to reasonable support levels (i.e., relatively low unitary support)(Ragwitz et al 2014), but since they have generally been quite effective in triggering RES-E deployment, the total support costs have skyrocketed in some occasions (i.e., high total support costs). An advantage of FITs is the long-term certainty of receiving a fixed payment, which lowers investment risk. In turn, this result in lowers financing costs and, thus, generation costs. Guaranteed network connection and priority access further reduce investor risk because investors are assured a market for the electricity they produce (Mitchell et al 2011). Noothout et al (2016), have found that a policy design that exposes investors/operators to no or low volume and price risks (such as the FIT), reduces cost of capital by about 100 basis points. FITs do not give incentives for RES-E generators to participate in the electricity market and to produce electricity when the market needs it most (unless a design element is explicitly provided to do so, see next section). Finally, FITs are probably the simplest primary instrument to implement.

4.1.2 FiPs (fixed)

Fixed feed in premiums offer a fixed payment in addition to the price that may be received in the electricity market. Although it is in many ways similar to the basic FiT instrument, FiPs differ in that they provide revenue in addition to output sales and require the marketing of output. This marketing requirement exposes the operator to risks, such as electricity price volatility that are not a feature of a FiT system. FiPs are generally considered more compatible with the principles of market integration and better able to reduce perverse incentives such as generating at times of negative pricing. They encourage RES-E generators to adjust generation in response to market price signals (de Jager et al 2011) and to produce electricity when the market needs it most (Nothout et al 2016). In short, FiPs are more compatible with electricity markets compared to FiTs (Ragwitz 2013). All different market places for selling RES power may be used, which may increase the value of RES. Creativity of RES generators for creating better forecasts, new balancing products, use of storage options, optimising plant design and operation etc. may be activated (op.cit.). 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)(EC 2013). FiPs include a higher degree of compatibility with electricity markets by promoting the active participation of renewable electricity generation in wholesale markets, providing exposure for example to price signals. FiP has also the potential to reward performance, as the income of producers is linked to the market price. As a result, these market responsiveness measures will in the medium term improve the market integration of RES-e producers. The costs of balancing falls on the RES-e generator, who will have incentives to develop ancillary markets to cope with increasing load variability (EC 2014).

Some authors, however, express a concern that not all operators can appropriately manage market risk (especially smaller actors), potentially reducing actor diversity and driving up costs and that large-scale decentralised direct marketing could negatively impact the quality of power generation forecasting (Ragwitz et al, 2014). Fixed FiPs also share some of the volume control and cost containment issues associated with FiTs. In the case of a fixed FiP, the policy costs (per MWh) are highly predictable but higher than expected electricity prices may encourage rapid uptake and impact overall support costs. In addition, the higher risks for investors in FiPs compared to FiTs (due to, both, higher revenue and balancing risk) would lead to higher costs of capital, which would result in higher generation costs. According to Rathmann et al (2011, p.71), both investment costs and operational costs are higher in FiPs than in FiTs. Investment costs are higher because, due to the more complex revenue structure, cost for structuring contracts may be higher and consultancy assessments of future power and balancing prices need to be paid for and because the requirements of banks to minimize risk via contracting (more expensive) established companies/ technology providers may be higher than in a FiT due to the higher revenue risk. Operational costs are higher because there are transaction costs for selling power, forecasting and balancing, which is not the case in FiTs. As it will be shown in a later section, different designs of FiPs achieve a different combination of investor risk and market exposure for producers.

4.1.3 TGCs without banding

Being technologically neutral, unbanded quotas with TGCs have traditionally been regarded as a static efficient instrument (Menanteau et al, 2003). The cheapest technologies are promoted. However, the

instrument has led to comparatively high remuneration levels for the mature technologies (Ragwitz et al 2014). The effectiveness has been comparatively low and the total support has been relatively low (i.e., high unitary support but low total policy costs)(CEER 2008, 2013, 2015). One of the reasons for the low effectiveness and relatively high remuneration levels is related to the higher risks for investors compared to FITs and FIPs and the comparatively higher capital costs. The higher risk under quota systems includes price risk (fluctuating power and certificate prices), volume risk (no purchase guarantee), and balancing risk; all three risks increase the cost of capital (Mitchell et al 2006). In order to be bankable, projects in a quota system need to ensure a stable revenue stream for certificates via a contract with a creditworthy counterparty, usually an energy supply company obliged under the quota obligation (Rathmann et al 2011). This is not needed in other instruments, such as FIPs or FITs. The higher capital costs would lead to higher generation costs compared to other instruments, which would result in a lower static efficiency. Rathmann et al (2011, p.69-70) observe that, with respect to FITs and FIPs, quotas with TGCs may result in both higher investment and operational costs. In a quota system – compared to a feed-in premium – banks and investors will either increase cost of capital in order to compensate for higher risks as described above. Or they may aim to compensate the higher risk from certificate revenues via requiring projects to only contract established companies / technology providers and use especially complete performance guarantees or warranties and the like. In the latter case the cost of capital would not be higher than in a feed-in premium, but investment cost and operating cost would increase: The reason that there are lower investment costs in FIPs compared to quota systems is that, in quota system, banks may require only contracting with established companies/ technology providers in order to minimize overall project risk. Due to the more complex revenue structure in a quota system higher cost for structuring contracts and consultancy assessments of future certificate prices occur. The reason that operational costs are lower in FIPs is that in a quota system banks may require especially complete and long performance guarantees, service contracts, warranties and the like in order to minimize overall project risks. According to Rathmann et al (2011), a FIP would reduce the LCOE by 10% compared to a quota system without floor price. These higher generation costs for projects being financed in a quota with TGCs have to be compared to the efficiency gains resulting from the greater allocative efficiency resulting from a technological-neutral instrument.

4.1.4 Investment subsidies

Upfront investment support covers capital costs and can take different forms, including grants, preferential loans and tax exemptions or reductions (EC 2013). The focus here is on grants. Supporting RES-E investment by providing grants to developers is a fairly common secondary instrument in the EU but its use is far more prevalent in the heating and cooling sector. It is generally thought to be most effective at stimulating investment in immature or niche technologies. Investment grants are not tied to output and experience in the USA has shown that their use as a primary support instrument (i.e. without an additional incentive for production) can sometimes lead to good project realisation but very poor project performance (Redlinger et al 2002). They decouple 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. Investment support 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 (EC 2013, p.11). It certainly does not stimulate maximum production over a plant's lifetime and may encourage capacity which is afterwards not optimally maintained and operated or plant design with generator capacity being too high compared to other parts of a plant. Therefore a balance has to be found between ensuring optimum production over the plant's lifetime and reducing its production cost via front-loading, which may include certain amounts of cash grants (Rathmann et al 2011, p.76).

According to Rathmann et al (2011, p.76), investment subsidies would have two beneficial features from an investor point of view: lower risks and lower interests to be paid. On the one hand, earlier repayment of loan and equity would lead to lower risks. Front-loading will reduce WACC slightly because negative events occurring in later years of a plant's lifetime have less impact on a project's financial result. Often manufacturer's performance guarantees and full service agreements are in place only during the first years of a plant's lifetime and front-loading leads to a smaller share of revenues being paid during the unsecured latter years. On the other hand, the lower interests to be paid are due to the project having to pay interest over a shorter period and/or for less loan/equity. The support on the other hand has to be paid earlier. This constitutes a macro-economic cost saving only, if for the support (paid by consumers or government budget) a lower / risk-free discount rate can be assumed. Therefore, probably lower support costs could be expected. Lower generation costs could also be expected. However, since production volumes can be expected to be lower, the generation costs over the lifetime of the plant and the unitary support should not necessarily be lower. The EC favours the use of this type of support. In its 2013 guidance for the design of support schemes it states that "where feasible, favour investment over operating support so as to avoid distorting efficient production decisions based on market price signals" (EC 2013, p.12). The fact that the productive performance of the installation is not optimised compared to other instruments may lead to a lower pressure on equipment manufacturers to produce the most productive equipment, which leads to lower incentives for innovation, which is detrimental for the dynamic efficiency criterion (emphasis on low equipment costs rather than higher revenues). The fact that investment subsidies are paid up-front may also be politically less acceptable, since the promotion costs become more visible in the short term.

4.1.5 Fiscal incentives

A range of fiscal incentives is possible with tax-exemptions being the most commonly applied. Tax exemptions may be based on investment or production. Production tax credits are functionally similar to FIPs with additional effective revenue available per unit output on top of the market value of the output. Investment tax credits on the other hand operate more like investment grants with a fixed incentive based on the size of the investment. In general, tax credits require that the operator has a large enough tax liability to allow for the incentive. While smaller actors may not have such a liability, so-called tax equity arrangements in which a third party investor shares the tax benefit with the developer are common (de Jager et al, 2011). Being budget-financed, they are subject to the political and economic vagaries of the moment and, thus, usually considered less stable than other instruments (financed through the electricity bill). Historical experience shows that support instruments relying on the government budget are more prone to abrupt or frequent policy changes than those instruments that do not rely on the budget. This is due to the fact that the budget is (annually) subject to heavy political discussions especially in times of constrained budgets or when new

governments are looking for options to cut expenditures in order to be able to finance changed political priorities. Off-budget financing may reduce risks of abrupt or retro-active policy changes, but does not prevent them completely (Rathmann et al 2011).

4.1.6 Soft loans

Soft loans are usually offered by governments, or government bodies (e.g., 'green' investment banks) with an interest rate below the market rate or longer repayment periods. Similarly to grants, they reduce the costs of capital and the amount of interests to be paid. The lower costs of capital result from different factors (Rathmann et al 2011, p.78): 1) Soft loans may indirectly affect other key financial parameters used by investors and other lenders, such as a longer economic lifetime, longer loan tenure and a shorter tail (time span between debt being fully repaid and end of economic lifetime). 2) Soft loans may help developing an immature loan market for (innovative) technologies, triggering more commercial banks to engage in RE financing, which leads to improved loan availability. 3) Some financiers see soft loans reducing the equity share. The lower interest to be paid represents a macro-economic cost saving only, if for the soft loan (subsidy) (paid by consumers or government budget) a lower / risk-free discount rate can be assumed (op.cit.).

4.1.7 Evaluation based on other assessment criteria.

The previous sections have focused on the pros and cons of non-auction schemes with respect to the criteria of static efficiency and cost-containment. However, as mentioned in the introduction of this report, policy-makers judge policies based on other assessment criteria apart from those. These criteria include the degree to which support policies are able to encourage the deployment of RES, dynamic efficiency, local impacts (employment creation and reductions in energy dependence) and sociopolitical and legal feasibility. This section discusses the pros and cons of different non-auction alternatives with respect to those "other" assessment criteria, focusing on the primary instruments (i.e., FITs, FIPs and quotas with TGCs).

A crucial aspect for some governments around Europe is whether the support scheme encourages innovation and a diversity of technologies and actors. The former two aspects are included in the dynamic efficiency criterion (see del Río et al 2015). Dynamic efficiency refers to the ability of an instrument to generate a continuous incentive for technical improvements and costs reductions in renewable energy technologies: i.e. an incentive positively to influence technological change processes in the medium and long term. This is a key benefit of investing now in renewable energy technologies because, while RES-E is not a cost-effective means of reducing CO₂ emissions today, it may be so in the future if investments are made now to accelerate its development. Those RES-E support instruments which favour the commercialisation of expensive technologies in niches tend to lead to quality improvements and cost reductions; this will allow us to have renewable energy technologies in the future to comply with more ambitious renewable energy and emissions reduction targets at reasonable costs. If currently expensive mitigation technologies have a large cost reduction potential with increased diffusion (as shown by several studies for energy technologies), then supporting them today would lead to welfare benefits in terms of intertemporal mitigation efficiency (i.e. cost-effectiveness in the short, medium and long term). In contrast to static efficiency, dynamic efficiency has an intertemporal perspective on costs. The impact of RES-E support schemes upon innovation in renewable

energy technologies has several aspects or “dimensions”: diversity; R+D; learning effects; and competition (see del Río et al 2012b).

Diversity is about supporting different technologies, but also different actors. Some authors claim that vested interests are a barrier to a transition to renewable energy technology systems (van den Berg and Kemp 2008). New energy technologies are often developed outside the established energy systems and engage non-traditional energy actors (Astrand and Neij 2006). Actors, networks and institutions involved in radical innovation processes are not identical to those performing activities that sustain an established system (Markard and Truffer 2008).

In general, it can be argued that, the more neutral the support scheme, the greater the level of static efficiency and the lower the level of diversity (of technologies, project sizes, locations and actors), although not necessarily the lower the support costs (in fact, technology-neutral instruments such as quotas with TGCs have led to excessive remuneration for some technologies, as mentioned above). The higher the level of effectiveness in creating a market for renewable energy technologies, the higher the level of dynamic efficiency.

In this context, FITs have been more effective than other instruments (i.e., quotas with TGCs) in creating a market for different types of renewable energy technologies and increasing the deployment of RES. This has sometimes had a negative side in terms of an uncontrolled increase in deployment for some technologies and, thus, skyrocketing of support costs, especially for very dynamic technologies experiencing substantial cost reductions over time (such as solar PV). But, on the other hand, the higher degree of effectiveness has positive impacts on several criteria, notably dynamic efficiency and local impacts (benefits). FITs have resulted in strong domestic industries in several countries (Mitchell et al 2011). The creation of a market for the technologies has led to technological diversity and innovation, i.e. a greater level of dynamic efficiency (see del Río et al 2012b, 2015). FITs may be particularly suited to supporting less mature technologies or small-scale applications, which have difficulties to bear the price risks or the transaction costs for participation in a market platform with professional traders (Held et al 2014). Furthermore, the instrument has been considered particularly suitable to encourage a diversity of actors compared to other instruments (Couture et al 2010). This is probably related to the lower risk, the creation of a space (market) for different types of technologies and investors and the simplicity of the instrument. As argued by del Río et al (2012a) and Mitchell et al (2011, p.58), which review an abundant literature on the topic, FITs tend to favour ease of entry, local ownership and control of RES systems and thus can result in wider public support for RES. Mendonça et al. (2009) found that steady, sustainable growth of RE would require policies that ensure diverse ownership structures and broad support for RES.

The local benefits have made this instrument quite attractive for policy makers willing to support renewable energy technologies and to develop a supply chain for them. In turn, their social acceptability and political feasibility can be deemed high in the initial stages of deployment, but the skyrocketing of support costs for some technologies in some countries reduced their political feasibility, leading to retroactive cuts in some countries (EPIA 2013). Furthermore, the EU State Guidelines calls their legal feasibility into question, although they leave the door open for their use under given circumstances.

In contrast, quotas with TGCs have generally been less effective than FITs in creating a market for renewable energy technologies, especially so for the less mature technologies, for which quotas with TGCs have hardly

been effective. They have not promoted a diversity of technologies where they have been implemented (Mitchell et al 2011) and, thus, their score on the dynamic efficiency criterion is deemed poor. In addition, they tend to lead to concentration of projects in certain locations where the resource (e.g., wind) is most abundant in an attempt to maximise their income. This is an outcome of the uncertainty attached to TGC prices, and may increase the likelihood of social acceptance problems due to NIMBY phenomena. Finally, they score poorly regarding actors' diversity. As stressed by EC (2013, p.10) they limit "provision of renewables only to large scale incumbents capable of "on balance sheet financing", or with access to cheaper debt financing". The high risks in the quota obligation system tend to favour incumbent players, since large companies are usually better able to hedge the prevailing price risks (Held et al 2014). Jacobsson et al (2009) and Verbruggen and Lauber (2009) argue that it is primarily incumbent actors who would benefit from the new market. The transaction and administrative costs of a TGC system are higher than with FIT, making participation of small-scale new entrants cumbersome, and therefore limited (Mitchell et al 2006). Their social acceptability and political feasibility is deemed uncertain. On the one hand, low effectiveness and high unitary support costs may be detrimental in this regard. On the other, the relatively low total support costs (given its comparatively low effectiveness) could make them attractive for policy makers. Their legal feasibility can be deemed high, in line with the State Aid Guidelines.

FIPs seem to be in an intermediate position compared to FITs and quotas with TGCs. Their dynamic efficiency can be expected to be greater than in quotas with TGCs, since they provide greater certainty to investors and are more likely to facilitate the creation of a market for renewable energy technologies. But they are probably less dynamically efficient than FITs (given the higher risks and lower market creation compared to this instrument). The diversity of actors being promoted is also likely to be intermediate. The lower risks of FIPs and greater simplicity of the instrument compared to quotas with TGCs is likely to encourage a greater diversity of actors. But risks in FIPs are higher than in FITs and, in addition, generators have to sell their electricity in the market. Both factors are likely to discourage small actors. Risks fall asymmetrically on different actors, with the smaller ones being less capable of hedging them. And finding a trader in the electricity market is also likely to result in higher unitary transaction costs for the smaller investors/generators. However, the fact that FIPs are regarded as more "market-compatible" makes them more legally feasible. They are more in line with the prescriptions of the EU State Aid Guidelines.

The following table summarises the above discussion, showing the pros and cons of different support schemes with respect to static efficiency and cost-containment and the other assessment criteria.

Table 7: Pros and cons of non-auction instruments with respect to relevant assessment criteria. Summarising the results of the analysis

		Static efficiency and cost-containment	Other assessment criteria
FIT	Pros	Relatively low unitary support costs (€/MWh). Certainty for investors (low risk premiums), which leads to a lower cost of capital enhancing static efficiency.	Quite effective in triggering RES-E deployment. Dynamic efficiency due to technological diversity and market creation feeding back on innovation along the whole supply chain.

	Cons	Increasing and high total support costs. Uncertainty on total support costs if large RES-E volumes are deployed. In turn, this may lead to retroactive measures, which increases risks and negatively affects static efficiency. In addition, least-cost technologies do not capture 100% of the market.	Social acceptability may be negatively affected in case of very high support costs. Argued not to support the RES-E integration when RES-E has more value. FITs are deemed less compatible with the principles of liberalised markets than other policy instruments.
FIP	Pros	Fixed premium offers fairly low and predictable unitary costs.	Increased market exposure leading to improved operational decision making (somewhat reduced incentive to produce when prices are negative). More compatible with the principles of liberalised markets than other policy instruments.
	Cons	If electricity prices are higher than predicted when setting the premium level total support costs may be higher.	Risks of direct marketing not being appropriate for smaller actors impacting actor diversity.
TGCs	Pros	TGCs are designed to minimize support costs (but have not always been effective at doing so). The relative ineffectiveness of TGCs to promote RES growth has limited overall policy cases.	Generally, TGCs require the separate marketing of output, and are therefore considered beneficial to market integration.
	Cons	Static efficiency promised by the instrument design often does not materialise. High risk premium resulting from the uncertain development of the electricity and the certificate price typically increase policy costs. Excessive remuneration for mature technologies often results.	TGCs have been shown to be less effective than FITs at stimulating RES growth in Europe. TGC (without banding) do not support a range of technologies and dynamic efficiency is low. May lead to geographical concentration and acceptance issues. Actor diversity is also not encouraged.
Investment subsidies (direct grants)	Pros	Straight forward and easy for developers to value. Lower capital costs for investors. Ambiguous impact on support costs.	
	Cons	Incentives often not appropriate to encourage strong production, undermining cost effectiveness. Disincentive to operate the plant as efficiently as possible	Not an appropriate primary instrument. Detrimental for dynamic efficiency
Fiscal incentives	Pros	Highly flexible policy tools that can be targeted to encourage	

		specific renewable energy technologies and to impact selected renewable	
	Cons		Not an appropriate primary instrument.
Soft loans	Pros	Reduction of investors' risks and, thus, capital costs, which is beneficial for policy costs, generation costs and effectiveness.	Maybe useful for specific technologies and actors. In particular, smaller actors which have difficulties in accessing credit.
	Cons		Not an appropriate primary instrument.

4.2 Design elements in non-auction instruments.

Many, if not all, of the primary instruments described above have been implemented design elements which aim to improve performance against criteria associated with cost containment or static efficiency. Other criteria may also be relevant and are discussed where appropriate.

The consideration of each instrument begins with a high level outline (Reference) of the key design elements. These are then used as the framework to consider the implications for the difference assessment criteria.

4.2.1 Quotas with TGCs

Reference: a quota with TGCs scheme without banding (neither credit multipliers nor carve-outs), without a floor price and with a penalty (for non-compliant suppliers) but no cap price (for compliant suppliers). There are no banking provisions. Being a purely technology-neutral instrument, the reference case for TGCs generally lead to high static efficiency. However, technological neutrality would have some drawbacks regarding other criteria. First, a excessive remuneration level for the lowest-cost technologies and the best locations can be expected (i.e., high unitary remuneration costs). This is unlikely to lead to high total remuneration costs, given the relatively ineffectiveness of the instrument. This ineffectiveness is particularly clear for less mature technologies. In turn, this triggers a number of negative consequences in terms of low dynamic efficiency and low level of local benefits. The lack of a market for the less mature technologies means that there is little incentive for innovation and for the creation of local supply chains. Low local benefits can be expected. In addition, the higher risks for investments in less mature technologies (given the volatility of support and/or the aforementioned lack of a market for those technologies) results in a low degree of actors' diversity. Technology-neutrality and their cons might be mitigated by design elements which make the instrument more technology-specific and/or reduce the risks of investments in less mature technologies (banding and floor prices, see table 8), without reducing its appeal in terms of political and legal feasibility (i.e., compatibility with the State Aid Guidelines).

Table 8: Summarising the discussion on the impact of different TGC design elements on the assessment criteria considered

		Static efficiency and cost-containment	Other assessment criteria
Cap prices	Pros	Limits the overall cost of meeting the obligation. Even if a cap is not officially imposed, the wholesale cost of electricity + the penalty price combined acts as an effective cap.	
	Cons	Effectiveness may be negatively affected (targets not fulfilled).	A cap on TGC prices can act as a disincentive to invest in more risky projects or less mature technologies
Floor price	Pros	Setting a floor prices for TGCs can avoid the value of the TGC declining as the target level for the obligation is neared. This in turn can reduce project risk for operators and allow more favorable cost of capital terms	Depending on the floor price set, this could act to support less developed technologies
	Cons	A floor price but no cap implies the possibility of unconstrained costs to the consumer/taxpayer if TGC prices spiral.	The effectiveness of TGC prices as a driver for investment is linked to the penalty prices that must be paid if the obligation is not met.
Banding: credit multipliers	Pros	Contributes to avoiding windfall profits.	Greater diversity of technologies and location. Increased incentive to invest in less developed technologies
	Cons	<p>Could lead to overinvestment in more expensive technologies. It adds complexity to the market. Lower volume control. It hampers the accuracy and control of target achievement compared to technology-neutral quota (Held et al 2014)</p> <p>Parameterising the multipliers for the different technologies is very sensitive for the performance of the quota and requires good knowledge of technology costs. The additional complexity of banded quotas makes the prediction of the certificate prices more difficult, which may imply higher risk premiums from investors. The price depends on the degree of target achievement which is much more difficult to predict in a banded quota system (Held et al 2014).</p>	

Banding: carve-outs	Pros	Assuming that there is a real or effective cap on TGC prices, could lead to development of less mature technologies, with cost reductions over time Contributes to avoid windfall profits.	Technology development, greater diversity of renewable technologies. In contrast to credit multipliers, but similarly to technology-neutral quotas, technology-specific targets maintain the advantages of predictable and controllable targets,
	Cons	Fragmentation of the TGC market. Lower liquidity and added complexity for operators.	Encourages the deployment of less mature, riskier and/or expensive technologies and undermines the market rationale' of the instrument
Banking	Pros	Reduces risk to operator, allowing lower cost of capital and project costs	Encourages project development in a more sustained way, rather than with a focus on annual targets (ie less lumpy)
	Cons	Can increase price volatility if they are stockpiled and released in one go.	Uncertainty about future TGC prices may act as a disincentive to invest

4.2.2 FITs

The analysis in the previous section is based on a reference case in which the level of a FIT is set administratively, without generation, capacity or budget caps and without traditional degeneration. There are periodic revisions of support for new plants, but based on the government's calculations (i.e., not on an independent entity). Caps (on capacity, budget or generation) have been regarded as main cost-containment mechanisms for FITs. Limiting the RES expansion and thus related policy costs provides higher predictability of policy costs and allows for a better planning of the future electricity system. By restricting the growth of RES, investment uncertainties for conventional power plants and other flexibility options that contribute to integrating variable RES-E are reduced (IRENA 2014). By providing volume and total cost control, they can avoid retroactive measures being imposed later, which would then lead to a higher risk for investors and greater risk premiums and capital costs, which may reduce effectiveness and end up with higher support costs. They might be useful for technologies with a very dynamic cost development such as Solar PV.

However, they have a number of disadvantages. In general, caps for RES development imply at least a partial transfer of market risks regarding the demand for RES-E from the public to renewable power plant operators, leading in turn to higher risk premiums.

They may also bring higher generation costs (i.e., lower static efficiency) and lower effectiveness. As argued by Rathmann et al (2011), the existence of caps and application processes for support may have three different negative effects. First, some projects do not gain support during their first application, but gain support one or several years later and can still be realized. The delay and repeated application for support will increase project development cost. Second, some projects cannot be realized because they never gain support or project developers give up applying. This leads to sunk cost for project developers. Project developers will aim to recover these sunk costs in other, successful projects, driving up project development cost of successful projects. Third, however, in support systems where support levels allow only moderate

overall project returns, the room for recovering sunk cost in successful projects is limited. Often financiers will not accept development fees higher than a technology- & project-size-specific percentage in investment cost (e.g. 5%). If that is not sufficient to recover sunk cost, project development in that country will be considered an unattractive business and less new project development will be started, leading to a drying up project pipeline and less future growth opportunities for that country.

Furthermore, caps may even be counterproductive for cost-containment. According to Lüthi and Wüstenhagen (2010), a country would need to offer 10-30% higher revenues in case a cap is applied in order to still attract investors/project developers.

The table below discusses the design elements that may be introduced to this reference case to improve performance against the goals of static efficiency and cost-containment.

Table 9: Summarising the discussion on the impact of different FIT design elements on the assessment criteria considered

		Static efficiency and cost-containment	Other assessment criteria
Support tied to electricity prices	Pros	Support is greater when demand is higher and, thus, prices are higher. This links RES-E generation to the evolution of electricity demand. Possibly higher static efficiency.	Better integration of RES-E in electricity markets (more in line with the evolution of electricity demand).
	Cons	Uncertainty on future total support costs and volume control (in the absence of caps) for the policy maker. RES-E support costs may increase more than expected if electricity demand and electricity prices increase more than expected. Greater risks for investors than when support is not tied to electricity prices, since the evolution of support is unknown. Higher risks lead to higher costs and, thus, lower static efficiency (and possibly higher unitary remuneration costs).	-
Demand-orientation	Pros	Lower system costs (peak-shaving)	Better integration in electricity markets
	Cons	Greater uncertainty on cost-control by policy makers since total costs depend on when RES-E is fed into the grid, with greater overall support if most electricity is fed when demand is high (in the absence of a generation cap).	-

Forecast obligation	Pros	More certainty on volume control by policy-makers, lower system costs (higher static efficiency)	Better integration in electricity market
	Cons	Greater costs for investors, lower static efficiency, possibly higher support costs.	
Generation cap	Pros	Effective to control RES-E generation and, thus, its associated support costs. Certainty for policy-makers on the total amount of policy costs.	Effectiveness, understood as certainty in reaching a given target, although it could involve a barrier to further RES-E (beyond the cap).
	Cons	The efficient functioning of plants (MWh of generation/kW of capacity) and, thus, the manufacturing of more efficient technologies by equipment producers is not encouraged.	Negative impact on the whole value chain and, thus, on dynamic efficiency (with respect to not having the cap) because market creation is constrained.
Capacity cap	Pros	Very effective to control installed capacity (and its associated support costs) in the short-term.	Effectiveness. The manufacturing of more efficient technologies is encouraged.
	Cons	Risk for investors in the form of access risk, leading to higher capital financial costs and, thus lower static efficiency. They cause stop-and-go in the market. If eligibility for support is provided on a first-come-first-served basis, it may lead to bubbles since project developers have an incentive to rush to be eligible for the FIT.	Negative impact on the whole value chain and, thus, on dynamic efficiency (with respect to not having the cap) because market creation is constrained.
Budget cap	Pros	Greatest certainty on budget control (i.e., minimisation of support costs).	Social acceptability for RES support may be enhanced (given the certainty on money spent) but if effectiveness is negatively affected (see below), the net impact on social acceptability would be uncertain.
	Cons	Risk for investors in the form of access risk, leading to higher capital financial costs (i.e., lower static efficiency). It may cause stop-and-go in the market.	Effectiveness is not ensured. Negative impact on the whole value chain and, thus, on dynamic efficiency (with respect to not

			having the cap) because market creation is constrained.
Traditional depression	Pros	<p>Investment security due to long-term price signal (leading to greater static efficiency). High level of predictability.</p> <p>Transparency and predictability of market participants. It mitigates the asymmetric information problems when setting tariffs.</p> <p>Reasonable option when cost development is quite predictable</p>	<p>It does not necessarily lead to sharp reductions in installed capacity in a given year (but probably gradual ones).</p> <p>It increases competition between equipment producers and, thus, triggers innovation.</p>
	Cons	<p>The setting of pre-established, appropriate depression rates is difficult, in particular for dynamic technologies, such as Solar PV. Administratively more complicated than a constant tariff (due to difficulties in setting the depression rates). This can result in high administrative costs, being negative for static efficiency. Too rigid if generation costs of the RETs do not evolve as expected. In the case of unanticipated cost developments, however, this design option is not able to adapt quickly to real cost reductions. Fixed depression rates may be well suited for technologies with predictable cost development and with low expected cost decreases. If depression rates are set annually, this introduces a small risk element into the support mechanism. Deployment volumes may increase in periods prior to the FIT reduction, as was the case in Germany (Grau 2014). Degression (all types) may lead to even stronger capacity growth by motivating investors to anticipate their investments with more favourable support conditions, therefore increases policy costs (Held et al 2014).</p>	<p>Effectiveness is not ensured.</p> <p>Ambiguous effect on social acceptability (+ due to cost control, - if effectiveness is negatively affected).</p>

Flexible degression	Pros	<p>The evolution of RES-E costs is more appropriately taken into account when setting the support levels than under traditional degression. Tariffs are adjusted as new circumstances arise. It facilitates that learning curve achievements are translated into price reductions. Capacity-dependent degression rates are suitable for technologies with a significant cost reduction potential such as solar PV in order to control policy costs. It provides governments with a clear picture on how attractive their tariffs are by highlighting how much new capacity is actually being added to the system over a period of time. Second, they provide investors with clarity about the timing and the extent of tariff changes. The design also lowers longer-term political risk by reducing the likelihood of an uncontrollable boom which could lead a government to cut tariffs suddenly or even retroactively.</p> <p>The success of degression mechanisms depends on effective design and administration. The specific design features of the mechanism, such as the setting of degression rates, capacity corridors, capacity caps, and the time period between successive revisions, are critical for the success of this adaptation measure (IRENA 2014).</p>	Effectiveness is not ensured, but better than with traditional degression.
	Cons	<p>Uncertainty on future levels of RES-E support.</p> <p>With respect to traditional degression or a capacity cap, it preserves investment stability to a higher degree but may be less effective in limiting the increase of support expenditures.</p>	
Periodic revisions	Pros	May enable policy-makers to reduce the information asymmetry that is the common source of over- (as well as under-) compensation.	

		Mitigates the rigidity of traditional depression.	
	Cons	Appraising the quality and independence of the advice may be difficult It requires precise knowledge of cost levels and may involve high transaction costs by means of required studies	Currently not favoured by European Commission (political and legal feasibility).

4.2.3 FIPs

The analysis in the previous section is based on a reference case in which the level of a FIP is administratively set, without generation, capacity or budget caps and without traditional depression. There are periodic revisions of support for new plants, but based on the government calculations (i.e., not on an independent entity). Neither floor nor cap prices are applied (the later could be adopted in the form of a sliding premium or CfD).

The table below discusses the design elements that may be introduced to this reference case to improve performance against the goals of static efficiency and cost-containment. Three main options are considered: fixed FIPs, fixed FIPs with cap and floor and sliding premiums.

Different designs maintain a different trade off between investors' risk and market exposure. As stressed by the European Commission, FIPs "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." (EC 2013, p.9). A greater exposure, however, comes with a higher cost of capital for investments. In a continuum from fixed FIPs to sliding premiums, with fixed FIPs with cap and floor prices in the middle, fixed FIPs would have the greatest market exposure and higher risks, whereas the opposite would be the case for CfDs which nevertheless, in the context of all non-auction support schemes seem to maintain a good balance between exposure and risks. In short, the choice of different design elements is motivated by the importance attached to different goals and assessment criteria. Volume risk is relatively high in both fixed FIPs and sliding FIPs compared to FITs (since the generators have to forecast and market their produced electricity). Price risk under fixed FIPs is higher compared to FITs. It is only slightly higher under sliding FIPs (Noothout et al 2016). Sliding premiums seem to maintain a better balance between market exposure and investors' risks. Still, a main issue is how to set the strike price.

Since many of the design elements under FIPs would share the same pros and cons of the respective design elements in FITs, those differential design elements will only be discussed in the following table.

Table 10: Summarising the discussion on the impact of different FIP design elements on the assessment criteria considered

		Static efficiency and cost-containment	Other assessment criteria
Fixed premium	Pros	Good predictability of policy costs (the premium is usually calculated considering long-term average electricity prices, but does not take into account short-term variations on monthly, daily or hourly basis (Held et al 2014))	Highest market exposure for RES-E generators
	Cons	<p>Unclear predictability of policy costs. Despite what is mentioned above, rising electricity price may lead to an accelerated development of RES capacity and thereby cause an increase in policy costs.</p> <p>Higher risks for investors (RES power plant operators have to bear the overall risks arising from volatile electricity prices, leading to higher risk premiums)</p> <p>Administrative complexity (Given that the level of the electricity price has to be considered, the determination of the premium level requires a good knowledge of future market development and is therefore rather complex. In this respect, the fact that increasing share of RES with low variable costs has led to decreasing electricity prices on the wholesale market should be taken into account (Held et al 2014).</p>	Detrimental for those actors less able to cope with risks (smaller actors).
Sliding premium (floating, CfDs)	Pros	<p>Can limit 'over-reward' at times of high wholesale prices.</p> <p>Plant operators of RES-E are not exposed to the overall risk of the electricity market price.</p> <p>The determination of the premium level is similar to that of fixed FITs, and may be based on LCOE or determined in auction procedures.</p>	
	Cons	Increases complexity for developers and therefore transaction costs.	

		Overall support costs become a function of electricity prices and therefore potentially volatile. The public has to bear higher risks regarding the policy costs, since they depend on the development of the electricity market Price (Held et al 2014)	
Cap-and floor prices in fixed FIP	Pros	Compared to a fixed FIP, the risks for investors are limited by the floor (lower capital costs). This reduces investors' risks and project development costs Compared to a fixed FIPs, the risks for the electricity consumer of higher costs are limited by the cap.	
	Cons		

5 Conclusions

Several alternatives exist to auctions regarding volume and cost control. This report has assessed a number of them. They do not only include instruments (whether primary or secondary), but also the design elements within specific instruments.

When evaluated against different criteria, none of the instruments and design elements is inherently superior. Trade-offs and conflicts between criteria exist. However, some are more conflicting than others, and some achieve better balances between criteria than others.

This means that achieving cost and volume control, certainly a major concern of government nowadays in the EU, and two of the main reasons why auctions have been regarded as a main alternative to achieve those goals, may come at a cost in terms of static efficiency, dynamic efficiency or diversity. In particular, different instruments and design elements achieve a different combination of investor risk and market exposure for producers.

Therefore, the choice for a specific instrument and design element will depend on the specific priorities of government and the specific context (institutional) conditions in the specific country.

All in all, the sliding premium under FIPs (also called floating premium or CfDs) provides a good balance between different goals and assessment criteria.

Note that many of the instruments and design elements considered in this analysis can be combined among themselves and also with auctions. In particular, it should not be forgotten that auctions can be used to allocate different instruments such as feed-in premiums, investment support or green certificates (EC 2013). While policy mixes may increase policy complexity, they may also mitigate the disadvantages of particular instruments and design elements regarding one specific goal or assessment criterion.

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