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THE VALUE OF DISTRIBUTED SOLAR PV IN SPAIN

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ABSTRACT

The objective of this study is to inform ongoing research and the debate in Europe on the redesign of electricity price models, self-consumption of electricity, and the redesign of tariff structures. This study for the first time applies the new rules agreed in the revised renewable energy directive that requires distributed solar photovoltaic (DSPV) to be remunerated at market value and may also include the benefits of DSPV to the grid, the environment and society. The study is based on two case studies of DSPV electricity generation in Spain. It assesses the value of DSPV for the Spanish electricity system, and ultimately for Spanish society as a whole.

Adapting the value of solar approach as developed and applied in the United States, it assesses the various costs and benefits related to the deployment of DSPV, including: (avoided) capital and capacity investments in transmission and distribution (T&D) infrastructure, (avoided) investments and costs of electricity generation, as well as environmental benefits.

The value of solar approach has been applied in

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several studies for a number of states and municipalities in the US, including Arizona, Colorado, California, New York, New Jersey, Oregon, Pennsylvania and Texas. The municipal utility in Austin (Texas) was the first to use the value of solar approach and adopted a value of solar tariff in 2013, recently followed by Oregon. Michigan is considering its adoption. For the first time, this study applies the approach to a European country.

To calculate the impact of DSPV, this study follows a scenario-based approach and uses an advanced energy model to assess the impacts of two different future deployment cases in detail: a case where no additional distributed solar PV is assumed to be added to the Spanish electricity system from 2015 on and a case with high penetration of distributed solar PV. By comparing different cases, we calculate the net value of DSPV on a national level.

The results of this study show that the benefits of large-scale deployment of DSPV far outweigh any incurred network costs and that DSPV has a net positive value for the system of around €39/MWh. This does not yet include the value of avoided CO_2 emissions. When including these into the equation, the net value increases further to between €48/MWh and €59/MWh. Because we study a system where PV is connected to the grid, we calculate the benefits for both self-consumed electricity and electricity injected in the grid.

This study also examines the direct financial effects of large-scale DSPV deployment on key stakeholders: households, the government and the system operator. Firstly, it examines the financial effects of DSPV under the current tariff regime. In the current situation there is no remuneration for surplus of electricity that is fed into the network. Secondly, the study assesses what would happen if a) surplus electricity were remunerated and if b) there were no 'transitory charge on self-consumed electricity' - or what is more commonly referred to as the 'sun tax'.

Under the current tariff regime, investments in DSPV are not attractive and are unlikely to take place, with payback periods exceeding 10 years. Under a potential regime, with sufficiently attractive measures to encourage investments, households and SMEs could potentially save on their energy bills by installing PV panels, while the government and system operators would be faced with a loss of income if the tariff structure of the power bill is kept the same. However, we find that the effect on revenue streams for goverments and system operators would only be moderate.

The positive value of DSPV could legitimise supporting its deployment. Any future design of tariff structures for DSPV should properly reflect this value, making investments sufficiently attractive, while at the same time distributing costs and benefits fairly across different stakeholders. In the case of Spain, net remuneration of the electricity fed into the grid at a price level around the spot price for electricity (€40/MWh, excluding CO_2 allowances under the EU Emissions Trading System) could make investments in DSPV sufficiently attractive for most households. Small and medium-sized enterprises (SMEs) would require some extra remuneration to make investment in DSPV attractive.

The approach adopted in this study can be translated to other EU countries and thereby contribute further to the design of new electricity market regulation and the setting of tariffs and incentives for DSPV systems that more accurately reflect their benefits, as well as any associated costs.

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INTRODUCTION

CONTEXT

A sharp decline in solar-photovoltaic (solar PV) costs is making electricity from this renewable energy source more competitive compared to retail electricity prices (IEA 2016). As a result, businesses and households increasingly produce and consume (parts of) their own electricity and are becoming active 'prosumers' (producers and consumers of electricity). The shares of solar PV and other renewable energy sources (RES) is growing. This is having an impact on electricity networks and current electricity tariff structures. As a result, EU member states are revisiting and redesigning their support policies, as well as discussing a redesign of electricity market tariff structures.

On 30 November 2016, the European Commission launched a package of measures on energy policy (referred to as 'Clean Energy for All Europeans'). Under the package, the EU aims to implement its 2030 climate and energy policy for the period 2021 - 2030. It includes proposals for a legally binding framework to give renewable energy self-consumption, prosumers (producers and consumers of electricity) and community energy a legal status and protection, and aims to remove legal and administrative obstacles. The underlying rationale is to (1) empower consumers and enable them to be more in control of their energy choices; and (2) allow consumers to become active participants in the energy market by making it easier for them to generate their own energy, store it, share it, consume it or sell it back to the market. On 27 June 2018, the negotiations between the Council, Parliament and Commission on the renewable energy directive concluded. The revised rules, which will apply from 2021, for the first time at EU level give all Europeans the right to generate, consume, store and sell electricity without fear of punitive taxes and fees. Under the new EU rules, electricity sold to the grid must also be remunerated at least at the market value and may also include the benefits of DSPV to the grid, the environment and society.

For the first time, this study applies these new EU rules in a European country: Spain. This approach aims to more accurately determine the value of distributed solar photovoltaics (DSPV) to the grid, the environment and society. The so-called 'value of solar' approach is already widespread in studies for a number of states and municipalities in the US, and has been used to adopt a value of solar tariff in the city of Austin (Texas) and the state of Oregon.

The issue of prosumers and self-consumption is much debated. This is in part because electricity market tariff structures were designed for a centralised electricity model, with centralised electricity from conventional sources (such as fossil fuels and nuclear power) travelling first through the Transmission System Operator (TSO) network and then the Distribution System Operator (DSO) network, before reaching the consumer. As more decentralised renewables and other new technologies, such as demand-side response, enter the market, the electricity model has become more decentralised, with decentralised generation feeding into the distribution network. This has raised questions about how electricity market tariffs are structured and how they must be redesigned for this changing reality. It also raises questions about how the new design can help the European Union comply with its climate change and energy policy objectives, and its commitments under the Paris Agreement on climate change.

Currently, electricity consumers in the EU commonly pay charges to the TSO and DSOs to cover costs related to the grid (referred to as distribution and transmission charges or grid tariffs) and to pay for the electricity that is supplied to them (these are only some of the charges paid for by consumers). Distribution and transmission charges were designed to cover the recognised costs for distribution and transmission (GEODE 2013). In most countries,TSOs, DSOs and utilities succeeded in recuperating their costs through an electricity price model primarily based on consumption. This volumetric rate model is seen as relatively equitable and fair because it assums that consumption is directly related to income.

However, this traditional electricity price model is under pressure as a result of various developments: new market entrants such as prosumers, aggregators and demand-side response providers (who help manage the use and demand for electricity) are entering the market. TSOs and DSOs increasingly facilitate the integration of renewable energy sources.

This increase in self-generation by prosumers has resulted in reduced consumption of electricity. Where tariff structures are based on volumes of consumption, this has led to the argument that prosumers are paying less towards overall transmission and distribution costs. Utilities argue that the costs stay the same and that these costs have to be distributed over fewer consumers, thereby increasing the tariffs for other consumers. This report argues that network costs only marginally increase and that the benefits of DSPV far way out these.

Under Spain's so-called sun tax, for example, prosumers have to compensate the system for the electricity they self-consume. This approach has contributed to a debate about whether prosumers are really a cost to the system and whether they should pay grid charges for electricity that never touches the grid. It also raises a question about whether prosumers should be penalised for reducing electricity demand during peak hours.

These developments ask for a rethinking and evolution of the way current electricity price models and tariff regimes are designed.

THE VALUE OF SOLAR APPROACH: A BASIS FOR SETTING TARIFF STRUCTURES AND DETERMINING A FAIR REMUNERATION FOR PROSUMERS

The value of solar approach aims to provide a basis to determine the level of reward for electricity from DSPV exported to the grid at a rate that is reflective of a) the value that solar provides to the electricity system overall and b) of any possible costs that DSPV incurs on the grid (Rocky Mountain Institute, 2017). It aims to strike a balance between ensuring a fair remuneration for prosumers, on the one hand, and adequate grid tariffs that allow DSOs and TSOs to recover their investments on the basis of the value that solar-PV has for society as a whole, on the other hand. It addresses some of the key concerns that are related to the current electricity price model and tariff structures and provides a means and basis for the design of a more future-proof regime.

GOAL AND OBJECTIVES OF THE STUDY

The objective of this study is to assess the value of distributed solar PV (DSPV) in Spain and to inform ongoing research, the debate on self-consumption and the redesign of electricity tariff structures. Spain is a particularly relevant case to investigate in detail. In 2015, the government introduced a new law on self-consumption that regulates self-consumption facilities, including distributed solar PV systems.[1] The Royal Decree 900/2015 prescribes new charges for grid access and use for self-consumed electricity (transitory charge on self-consumed electricity - even though this electricity never enters the grid) and batteries[2] (charge on installed capacity). It practically does not allows the remuneration of the surplus electricity that is exported to the grid. Since the law was introduced, the installation of DSPV has almost come to a halt as investments in PV have become unattractive for households and SMEs. Many already existing systems are currently loss-making, as the law applies retroactively (Prol et al. 2017).

The introduction of the law should be viewed in the context of several developments. The financial crisis has constrained Spain's budgets and expenditures on renewable energy and was followed by the retroactive reform of incentives to existing renewable projects. In 2008 alone, the country added 2.6 GW of new solar PV systems, increasing total installed solar PV capacity to 3.5 GW (JRC 2009).

From this moment on, the installation of new photovoltaic systems came to a standstill, followed by wind energy (in 2012) and then solar thermal energy (at the end of 2013). In the following years, employment in the renewable sector in Spain collapsed by 40% between 2011 and 2014. Spain sank in global rankings on the attractiveness for investments in renewables, from second place to number 29, behind countries like Peru, Pakistan or the Philippines.

The Spanish electricity system also faced a 'tariff deficit', with revenues from the electricity system not covering its incurred and current costs (Espinosa, 2013). To avoid this, the electricity tariff structure was changed and most charges were passed to the fixed part of the rate depending on contractual capacity. The charges of an average household almost doubled between 2013 and

1 The Power Sector Law (Ley del Sector Eléctrico, LSE) 24/2013 introduces self-consumption facilities in the Spanish regulations. The Royal Decree 900/2015 contains specific self-consumption regulation, including the administrative, technical and economic modalities. Source: IEA Policies and Measures Database. Available online: https://www.iea.org/policiesandmeasures/pams/spain/name-152980-en.php

2 It only applies if the installation has batteries that reduce the power contracted or if the peak consumption exceeds the power contracted with the utility. This charge will be paid for the hours of self-consumption.

2014, going from accounting for around 35% of the average electricity bill, to 60%.

The regulation on self-consumption was defended by the Spanish Government as a new way to contain future lost revenues for the grid, rather than to support the further deployment of renewables (Prol et al 2017). After the introduction of the new law, growth stagnated further with just 55 MWp and 135 MWp of new capacity installed in 2016 and 2017 respectively, mainly installations for the purpose of self-consumption and systems not connected to the grid in the agricultural sector.[3]

The Spanish self-consumption law can be seen as an attempt by the Spanish government to revise its electricity tariff structure to make its electricity system more financially sustainable. It has however since been fiercely criticised for making household and small business investments in solar PV unattractive and for making prosumers and citizens artificially responsible for fixing a poorly designed electricity rate[4].

This study aims to provide insights into the value of DSPV for the Spanish electricity system and ultimately for Spanish society as a whole. Following the value of solar approach, it assesses the various costs and benefits related to its deployment.The study also examines the direct financial effects of large-scale DSPV deployment on key stakeholders: households, the government and the system operators (TSO/DSO). This financial analysis is performed for two regions: Andalusia and Catalonia. The required extra investments for the electricity network is estimated and taken into account in the financial analysis.

This study can thereby contribute to the design of new electricity market regulation and the setting of tariff structures and incentives for DSPV systems, in particular to include both costs and benefits. This is of course particularly relevant for Spain, but the approach can be easily transposed to other countries in Europe.

Although the value of solar approach can and has been used in the US to determine and set remuneration levels and grid tariffs for DSPV systems, this study does not aim to do so. Rather, it should be seen as a first-of-its-kind study that applies the value of solar approach to an EU country. So while we assess the value of solar as such, we have not determined what would constitute a fair remuneration for electricity from DSPV electricity, on the one hand, and fair payment for both the grid electricity consumed (utility cost) and for the use of the grid (grid tariffs), on the other hand. This is ultimately a political and policy issue, where a multitude of factors may play a role. This study can however provide an informed basis for such decisions.

3 PV Magazine February 2018. https://www.pv-magazine.com/2018/02/06/the-rebirth-of-spains-solar-sector-135-mw-of-new-pv-systems-installed-in-2017/

4 The regulator, CNMC, also adduced in its comments to the draft Royal Decree on self-consumption that the lack of a clear methodology to establish the rate and costs allocation among different consumers should have been a reason not to put forth the Royal Decree. https://www.cnmc.es/sites/default/files/1205554_5.pdf

DETERMINING THE VALUE OF SOLAR FOR SPAIN: APPROACH AND SCOPE

For calculating the impact of DSPV, this study follows a (scenario-based) case approach and used the Energy Transition Model to model the impacts of two different cases. By comparing different cases this study calculates the value of DSPV on a national level. The national scenarios are then translated to a regional level to calculate the financial impact on the different stakeholders. This chapter explains these steps. More details on the approach and assumptions can be found in the Annexes.

THE ENERGY TRANSITION MODEL

The Energy Transition Model (ETM)[5] has been used in this study to model and determine the impact of two different cases: a case where no additional distributed solar PV is assumed to be added to the Spanish electricity system from 2015 on and a case with high penetration of distributed solar PV (see further paragraph 2.3 below). The ETM is an interactive tool for energy modeling, allowing the user to create and explore scenarios for the energy future of countries or regions. The ETM uses detailed information about technologies and includes hourly demand (and supply) profiles. The ETM is capable of calculating the impact of of changes in demand and supply on CO_2 -emissions, energy use, renewability, security of supply, costs and many more aspects.

The stakeholder analysis (ETM-SA) is a module of the ETM that gives insights in the effects of the energy transition on a regional/local and even individual level. ETM-SA is able to model energy flows on a 15 minute resolution and can assign tariffs to the energy flows. With ETM-SA both the financial impacts as well as the effects on infrastructure can be modelled. By providing insight into the total business cases for the different stakeholders and the limitations of a local infrastructure, informed choices can be made to develop and plan energy related matters, including the impact of DSPV installations on the system. ETM-SA allows the user to explore the impact of changing technologies, innovative strategies and helps to identify new electricity price models. In this study ETM-SA is used to explore the financial effects of DSPV on consumers, the electricity system operators and the government.

The ETM and ETM-SA are both free to use and open source. This means that everyone can view the scenarios online, get insight in assumptions that have been made and make their own variations on scenarios. As the ETM is continuously under development (specifications of technologies are updates, new features are included) the results in the scenarios might deviate slightly from the results presented in this study.

All technologies used in this study have specifications that are defined and documented in the Energy Transition Model:

- For general information see: https://pro.energytransitionmodel.com/
- For documentation see: https://github.com/quintel/documentation
- For detailed specification and sources see: http://github.com/quintel/etdataset-public/

5 The Energy Transition Model is accessible online, including all documentation https://energytransitionmodel.com/

- It is assumed that the investment costs of distributed PV are €1.3/Wp (Fraunhofer 2015).

WHAT DETERMINES THE VALUE OF SOLAR?

A variety of categories of benefits and costs of DSPV are considered in evaluating its value. These categories and a short description are presented in the table below.

Table 2.1 Typical cost/benefit categories that together form the value of solar. Source: based on Rocky Mountain Institute E-Lab 2017 and NREL 2014.

<table>
<tr><th colspan="2">Typical cost/benefit categories</th><th>Description</th></tr>
<tr><td colspan="2">(Avoided) costs of upgrades of transmission and distribution (T&D) infrastructure</td><td>(Avoided) capital and capacity investments in T&D infrastructure</td></tr>
<tr><td rowspan="3">(Avoided) investments in and costs of electricity generation</td><td>Avoided capital and capacity investment in generation infrastructure</td><td>Avoidance of upgrades to or construction of new power plants and associated costs to meet demand</td></tr>
<tr><td>Avoided O&M costs</td><td>Avoided expenditures on the operation and maintenance of central power plants</td></tr>
<tr><td>Avoided fuel costs</td><td>Reduced fossil fuel consumption required for thermal power generation (coal, natural gas, uranium) and thus avoided fuel costs</td></tr>
<tr><td colspan="2">(Avoided) grid losses</td><td>Avoidance of grid losses from central power plants. Because DSPV generates energy close to the consumer, such losses are avoided.</td></tr>
<tr><td colspan="2">Environmental benefits</td><td>Avoidance of greenhouse gas emissions and other pollutants.</td></tr>
<tr><td colspan="2">Social benefits</td><td>Economic development (jobs, added value and tax revenues)</td></tr>
<tr><td colspan="2">Market price response</td><td>Reduced fuel commodity prices due to a decrease in demand. Electricity spot price changes because of changes in demand for central power generation.</td></tr>
</table>

Social benefits are not included in this study as approaches vary largely and they are often disputed. A wide variety of literature exists that has assessed the macro-economic impact of solar PV and it is beyond the purpose of this study to redo these (cf. IRENA 2014 and APPA 2017). Market price responses are also not include because fuel commodity prices are largely determined on an international level and there is uncertainty on how the power markets will develop when penetration rates of wind and solar PV grow, increasing the share of power production with near-zero marginal costs.

In addition to the above listed categories, there are a number of other categories that have been less often assessed in studies. These are: the value of grid support services that solar systems can deliver as well as financial and security risk. Only a minority of studies have included these categories and there is less agreement on the approach for estimating values (Rocky Mountain Institute 2017). We have therefore not included these categories in this study although they may be addressed in follow-up studies.

A CASE-BASED APPROACH

This study applies a case-based approach, where two possible future situations are compared to determine the value of DSPV. The approach takes into account other foreseen developments and embeds solar PV developments in a broader context.

The two cases that are investigated are based on a study performed by the Universidad Pontificia de Comillas for Greenpeace (2017). From this study, we used the low electricity demand and high renewable(energy scenario (called in the study D3 high RES) as a basis for the two cases. In the D3 high RES scenario, nuclear and coal power are phased out by 2025, electricity efficiency is improving at higher rates (compared to the reference scenario and historic rates) and renewable electricity experience high growth rates. For this study, two variations on the D3 high RES scenario were developed:

- **A distributed solar PV (DSPV) case**: This is the D3 high RES, where all PV added between 2015 and 2030 in this scenario is assumed to be small scale and installed on buildings. This means 17 GW of distributed solar PV, corresponding to a 11.9% of the electricity demand and that 40% of households and SMEs would become prosumers.

- **No Additional PV case**: This is the D3 high RES, except no new solar PV is added after 2015. Instead, the Spanish power system will rely more on natural gas powered plants compared to the current situation and the original D3 high RES scenario.

These cases were developed to compare the impact of DSPV, especially in terms of distribution network impacts and translated into input for the ETM[6] to model the impact on the Spanish power system overall. The No Additional PV case is not a business-as-usual case, but should rather be regarded as a reference to calculate the impacts (emissions, costs, fuel use) on a macroscale and from a system perspective. These cases represent two extremes: few DSPV installations versus a very high penetration. This is done on purpose to make the impacts of distributed solar PV on the power system most visible.

6 The ETM does not include the option of pumped hydro storage. To simulate the flexibility from pumped hydro, the same amount of power was stored in batteries in the ETM cases. The ETM also models higher transmission losses. Both the difference in storage efficiency between batteries and pumped hydro and transmission losses are compensated with changes in gas power generation. With this approach, final electricity demand is nearly the same in the ETM cases and the Greenpeace scenarios.

Table 2.2 presents the different power generation mixes for the two cases.

*Table 2.2 Power generation mix and installed capacities according to the Distributed and the No additional PV case, in 2030. TWh.[7] Central Solar includes concentrated solar power. *Green gas is applied in natural gas plants. **Oil is only used in a very small number of industrial CHP's. ***About 35% of electricity from DSPV is self-consumed.*

Source	DSPV 2030 (TWh)	DSPV 2030 (GW)	No additional PV 2030 (TWh)	No additional PV 2030 (GW)
Coal	0	0	0	0
Natural gas	101	34.7	129	35.2
Green gas*	9	*	11	*
Nuclear	0	0	0	0
Solid biomass	2	0.3	2	0.3
Wind	76	33.3	76	33.3
Hydro	13	9.2	14	9.2
Oil**	1	<0.1	1	<0.1
Geothermal	3	0.4	3	0.4
Waste	3	0.6	3	0.6
Solar - central	14	7.6	14	7.6
Solar - distributed	30	16.8***	0	0
Import	1		2	
Demand	250		253	
Total	252		254	
Losses	20		23	

7 This table represents the sources of power. The ETM distinguishes more generating technologies, for example: natural gas is subdivided in CCGT, conventional (single cycle), CHP motors and CHP turbines.

The net value of solar PV

By comparing operation and maintenance (O&M) costs , capital and fuel expenditures in the two cases, the costs and benefits of solar are determined and a net value is calculated.

To combine the different costs and benefits associated with DSPV and arrive at a 'net value' of solar, we will levelise the costs and benefits and express net value per MWh of additional DSPV.

Levelising refers to dividing the total costs (including capital, O&M and fuel costs and interest rates) over the electricity generation (or, if calculating levelised cost of conserved carbon, total avoided CO_2 emissions) from a generation technology over its lifetime.

In this study we do not only levelise the costs of natural gas and DSPV power generation (as provided in section 3.3), but we also levelise the avoided costs of natural gas power generation due to deployment of DSPV. To do this, the following components are divided by the additional (compared to the No Additional PV case) DSPV production:

- Total avoided annual fixed O&M costs of natural gas power generation;
- Total avoided annualised investments (as provided in section 3.1) in natural gas power generation. To annualise the avoided investments we applied a technology lifetime of 30 years and an interest rate of 4%.

Both avoided fuel costs and variable O&M costs can be obtained directly, as one MWh of additional DSPV results in the reduction of one MWh of natural gas power.

The avoided cost per MWh can now be aggregated, resulting in the gross value of DSPV. Subtracting the additional network costs per MWh yields the net value of DSPV.

Because we apply a system approach, we do not distinguish between self-consumed and excess DSPV power injected in the grid when calculating and levelising DSPV (avoided) costs. Since the benefits of DSPV are highest when connected to the grid, one cannot distinguish between self-consumption and injection when calculating the value of solar. However, we consider the level of self-consumption when studying the financial impacts on different stakeholders.

Detailed cost assumptions are provided in the ETM. Links to the cases are provided in Annex 3, as well as the methodology to calculate levelised costs.

GRID LOSSES

One of the benefits of DSPV is that it has the potential to reduce grid losses. If the produced electricity is self-consumed, losses will be reduced as less electricity is transported over the grid. Current losses in Spain are estimated to exceed 10% of the total power production (based on the IEA energy balance). The extent of loss reduction through DSPV and self consumption depends on the distance electricity has to be transported and the voltage levels the electricity travels through. The highest loss reduction is achieved when DSPV electricity that is fed into the grid is consumed in the neighborhood, which prevents losses in for example transformation and long distance transmission.

More detailed modelling of the electricity network, including modelling per voltage level and enabling a more detailed analysis of the effect of decentralized electricity production, is currently being developed for the ETM. Table 2.2 shows that with the approach taken in this study the grid losses are roughly 3 TWh (15%) lower in the DSPV case than in the case with no additional PV.

CALCULATING THE (AVOIDED) CAPITAL AND CAPACITY INVESTMENTS IN THE ELECTRICITY TRANSMISSION AND DISTRIBUTION NETWORK

In this study the DSPV and No Additional PV case are compared to estimate the net change in investments in transmission and distribution infrastructure as a result of the deployment of DSPV. Benefits occur when DSPV is able to meet rising demand locally, relieving capacity constraints upstream and deferring or avoiding transmission and distribution (T&D) upgrades. Costs occur when additional T&D investment is needed to support the export of surplus electricity from DSPV to the grid.[8]

The impact of DSPV on the electricity grid depends on several factors: the current capacity of the grid, the current load on the grid, the amount of DSPV, the spatial distribution of DSPV, the future change in demand caused by other factors than DSPV. Our aim for this study was to calculate the effect of DSPV on specific detailed areas and to extrapolate our conclusions. However, it has proven very difficult to obtain detailed information of the current capacity of and load on the electricity grid as this information is classified. We therefore applied an approach which allows for the estimation of the order of magnitude of required extra investments in the electricity network.

In this study an assessment of required additional investments in the electricity transport and distribution network is performed for the region of Andalusia only. There was ***not*** enough information available about the network in ***Catalonia*** to perform a similar analysis. The outcome of the assessment should therefore be interpreted as an order of magnitude estimation of the required additional investments. The results are used in the financial impact analysis for both Andalusia and Catalonia.

For ***Andalusia***, information ***was*** available on the components of the current transportation and distribution network, their replacement values and the average load of several components of the distribution network. We were therefore able to model the effect of DSPV on the various voltage levels of the electricity network in ETM-SA[9]. As there was no detailed (e.g. hourly) information available on the capacity and load of the current electricity network, we could only study the effects on the average network. Because of the decrease in demand, the peak load decreases slightly for all voltage levels. On the LV level the peaks caused by PV production are not higher than the current peaks caused by demand. **Therefore, the effects of DSPV on the total (averaged) network is negligible**. Annex 1 provides details on the impacts on the T&D network. However, because a grid is not homogeneous, capacity problems (overload of the network) due to feeding back electricity to the grid might occur at specific locations and times. Furthermore, even though cables will have no issue to support a changed flow of electricity, a protection problem could occur in other components when the direction of power is changed as a result of DSPV.

A more detailed approach to determine the effect of DSPV on the network is to take the assets into account and model. This approach was fol-

8 Text adapted from Rocky Mountain Institute E-Lab. 2017.

9 See Annex 1 for details

lowed in the study 'Flexibility of the power system in the Netherlands' (FLEXNET) (ECN 2017) that has been has been carried out by a consortium of system operators (both distribution and transportation) in The Netherlands to calculate the network effects of variable renewable energy. For multiple scenarios, the required percentage of overloaded assets at different levels of the distribution grid were calculated, while the effects on the transportation grid were assessed more generally. For the so-called R2030 scenario the FLEXNET study found that 2% of the low voltage cables would be overloaded, 5% of the distribution transformers, 1% of the medium voltage cables and 6% of the substation transformers. The study states that for the high voltage network and the transmission network, no assets will be overloaded.

The situation in Spain differs from the situation in The Netherlands. The available capacity on the various voltage levels is different for the two countries. For the components for which we have information on the available capacity, the grid in Andalusia has more available capacity than the grid in The Netherlands (see table below). On the other hand, residential electricity use in Andalusia is roughly 40% of total electricity consumption, while in the Netherlands this is 20% (in Spain this is 30%). Therefore, changes in the residential sector will have more influence on the electricity network of Andalusia and Spain than on the electricity network of the Netherlands. As we use detailed information on the components of the grid in Andalusia, the approach adopted in this study does correct for differences in, for example, population density.

In this study we follow the conclusions from (ECN 2017) and combine this with information on the current network in Andalusia to calculate the network investments required for Spain in the DSPV scenario. As the current situation in Spain is different from the current situation in The Netherlands and Andalusia differs from the rest of Spain, this approach is only suitable for an estimation of the order of magnitude of the investments required in the electricity network when DSPV is integrated in the system. If this order of magnitude of the investments turns out to be significant with respect to other investments

Table 2.3 Available capacity of the electricity network in Andalusia and in The Netherlands.

Voltage level	Available capacity Andalusia[10] [%]	Available capacity The Netherlands[11] [%]
HV network	83	67
HV/MV transformers	65	25
MV cables	N/A	25
MV/LV transformers	N/A	67
LV cables	N/A	17.5

10 Source: Agencia Andaluza de le Energía

11 Source: ECN 2017

further study on the effect of DSPV on the electricity network has to be carried out.

DETERMINING THE FINANCIAL EFFECTS ON STAKEHOLDERS

The installation of DSPV will have different impacts on different stakeholders. It is therefore important to understand the different perspectives about the benefits and challenges of distributed solar PV. This study therefore also assesses the financial impact on these stakeholders:

- Consumers/Customers:
  - Three types of tariffs for households (with and without PV installations <10 kWp);
  - Small and medium sized enterprises (with and without PV installations >10 kWp).
- The government;
- System operators[12].

The financial effects on the different stakeholders in Spain vary per region as a result of differences in demand. This study therefore investigates two regions in detail: Andalusia and Catalonia. These two regions were selected because they are the largest provinces in terms of population[13] and they are geographically separated. Due to these different characteristics, consumers in these regions have a different electricity demand.

In this study, ETM-SA is used to explore the financial effects of DSPV on various consumers, the system operators and the government. The estimation of the required additional investments is part of the financial analysis. There is special attention for the payback period of solar PV in various cases and the effect of changes in tariffs on these payback periods.

By applying the same ratio for present and future demand as in the national cases (No Additional PV and DSPV) we translate the national cases to Andalusia and Catalonia. Details can be found in annex 1.

The current electricity price model and tariff structure for prosumers in Spain

The Royal Decree differentiates between two self-consumption types:[14]

- **Type 1: 'Supply with self-consumption'**. Applies to customers with installations not larger than 100 kWp where the electricity is only produced for self-consumption. Surplus electricity may be exported to the grid but it is not remunerated, with the exception if people register as an electricity production business and comply to the same requirements as any supplier of electricity. Type 1 self-consumers with an installation larger than 10 kWp are subjected to pay the the transitory charge on self-consumed electricity (popularly referred to as the 'sun tax'). They pay a variable rate for electricity that is produced by PV and is self-consumed by the customer. Type 1 self-consumers with an installation equal or less than 10 kWp are exempted from the transitory charge on self-consumed electricity if they waive reimbursement.

12 In this study system operators include both distribution system operators (DSO) and transmission system operators (TSO)

13 Andalusia 18%, Catalonia 16% of total population in Spain, based on Eurostat: http://ec.europa.eu/eurostat/cache/RCI/#?vis=nuts2.population&lang=en

14 The Power Sector Law (Ley del Sector Eléctrico, LSE) 24/2013 regulates self-consumption facilities, and in particular distributed small scale solar PV systems. The Royal Decree 900/2015 contains specific self-consumption regulation, including the administrative, technical and economic modalities. Source: IEA/IRENA Joint Policy and Measures Database Policies and Measures Database. Available online: https://www.iea.org/policiesandmeasures/pams/spain/name-152980-en.php

- **Type 2: 'Generation with self-consumption'.** Applies to customers with a single installation or to a supply point associated to one or several installations connected within its grid, or which share connection infrastructure with it or is connected to it.[15] The surplus of the generated electricity can be exported to the grid and is remunerated.

This study concerns customers with installations < 100 kWp. As long as they do not receive remuneration for surplus electricity these customers are type 1. In this study we also consider the case with remuneration and explore the impact of the transitory charge on self-consumed electricity on the payback periods of PV.

In this study we consider four stakeholder groups: customer (DSPV owners/consumers), the electricity supplier, the system operator[16] and the government. In this study we consider The customer pays both fixed charges[17] (proportional to the connection capacity) and variable tariffs[18] (per kWh of electricity consumed). As consumers, all prosumers keep paying all these fixed and variable charges over the electricity they consume from the grid but, in addition (unless they waive remuneration of surplus electricity) they pay a transitory charge on self-consumed electricity.

There are three different tariffs for households: bono social (vulnerable customer), PVPC (regulated tariff) and Mercado libre (free market tariffs). The table below shows the percentages of households (of all households) that fall under a specific tariff category.

Table 2.4 User group as percentage of all households

	User group as percentage of all households	
	Andalusia	Catalonia
Bono social	12%	6%
PVPC	48%	40%
Mercado libre	40%	54%

The table 2.5 presents the tariffs that apply for the different user groups of households[19]. The taxes included are tax of electricity (5.1127%) and VAT (21%). The 'Transitory charge on self-consumed electricity' is not charged to consumers with installations with a capacity below 10 kWp with no excess electricity or not retributed excess electricity.

15 IEA/IRENA Joint Policy and Measures Database

16 In this study system operators include both distribution system operators (DSO) and transmission system operators (TSO)

17 These fixed charges include for the retailer commercial margin and the system charges (the HV/LV grid connection), "old" renewables energy feed-in remuneration, financiation of the tariff deficit debt, extra-peninsular compensation, incentives to waste energy and non renewable cogeneration, tax and others.

18 The variable charges includes the market price of electricity, a variable commercial margin for the supplier plus additional costs (intradaily) market price, capacity payments, ancillary services, SO operation, interruptibility service a variable part of the system charges and tax.

19 Based on information received from Generalitat de Catalunya

Table 2.5 Consumption tariffs and charges for households with installations < 10kWp, assuming 4.4 kW power connection. Annual consumption of the user groups are shown in annex 1.

Paid by	Paid to	Unit of measurement	User groups and respective tariffs (EUR)		
			Bono Social	**PVPC**	**Mercado Libre**
Customer (households with DSPV <10kW) Rate 2.0A	Supplier	kWh of electricity consumed from network [€/kWh]	0.058	0.077	0.085
	Supplier	Fixed part of electricity bill [€/year]	10.3	13.7	0.0
	System operator	Fixed part of electricity bill [€/year]	126	167	167
	System operator	kWh of electricity consumed from network [€/kWh]	0.033	0.044	0.044
	System operator	kWh of electricity self-consumed (transitory charge on self-consumed electricity) if surplus electricity is remunerated [€/kWh]	0.0549	0.0549	0.0549

Source: Generalitat de Catalunya.

The tariffs in the table above relate to households. To examine the business case of small and medium sized enterprises (SMEs) we looked at customers from tariff group 3.0A and assumed a PV installation with a capacity of 15 kWp. The tariffs for these customers are time-dependent and vary during the day and between summer and winter. Details on these periods can be found in annex 3. The costs of electricity is based on the hourly market price[20] (taking losses into account[21] and adding € 3/MWh profit margin for the supplier[22]), the costs SMEs pay to the system operator are shown in the table below. The taxes included are tax of electricity (5.1127%) and VAT (21%).

20 The Energy Transition Model determines the electricity market price on an hourly basis. This price is used to determine the electricity costs for SMEs.

21 Customer electricity price (€/MWh) = electricity market price (€/MWh) / (1-network energy loss rate). Network energy loss rates are based on information from Red Eléctrica de España (REE) and obtained from GenCat. Grid losses are specified per month and per period (period 1, period 2, period 3).

22 Based on information from GenCat.

Table 2.6 Consumption tariffs and charges for small businesses with installations > 10 kWp. Annual consumption and connected power of SMEs are shown in annex 1.

Paid by	Paid to	Unit of measurement	User groups and respective tariffs (EUR)		
			Period 1	**Period 2**	**Period 3**
Customer SME (3.0A)	System operator	Fixed part of electricity bill [€/kW/year	40.73	24.44	16.29
	System operator	kWh of electricity consumed from network [€/kWh]	0.01876	0.01258	0.00467
	System operator	kWh of electricity self-consumed (transitory charge on self-consumed electricity) [€/kWh]	0.02057	0.01370	0.00895

THE VALUE OF DISTRIBUTED SOLAR PV IN SPAIN

A variety of categories of benefits and costs of distributed solar PV (DSPV) are considered or acknowledged in evaluating its value (see chapter 2.2). In this study, the following categories are assessed:

- (Avoided) capital and capacity investments in transmission and distribution (T&D) infrastructure;
- (Avoided) investments and costs of electricity generation:
  - (Avoided) expenditures on operation and maintenance of central power plants;
  - Reduced fossil fuel consumption required for thermal power generation (coal, natural gas, uranium) and thus avoid fuel costs. Because in Spain fossil fuels are largely imported (IEA 2017b), avoiding this, would lead to a reduction of imported fuel costs for the country as a whole;
- Environmental benefits.

The results of the assessment are presented for each individual category in the sections below. Subsequently, the resulting total net value of solar PV is calculated (section 3.4).

(AVOIDED) CAPITAL AND CAPACITY INVESTMENTS IN T&D INFRASTRUCTURE

In this study, the required additional investments in the electricity transport and distribution network as a result of DSPV are calculated, albeit globally, within the borders of a set of assumptions as set-out in chapter 2.

The total additional required upfront investment costs in transmission and distribution (T&D) infrastructure in **Andalusia** to integrate DSPV are €0.41 billion compared to the situation today. With an assumed lifetime of the infrastructure of 40 years, this results in depreciation costs of €10 million per year.

The additional operation and maintenance costs are estimated to be €5.2 million per year. Together, the additional upfront and variable T&D infrastructure costs required to integrate the DSPV are 15.2 million per year. This is €3.40 per year per household or **€2 for each MWh of produced power from distributed solar PV**[23] (both self-consumed and injected). These are net-costs: self-consumption will likely reduce the load on the grid and mitigate investments, whereas injection of electricity (especially if it results in additional flows to the transmission network), results in some - but limited - additional investments.

For the grid in **Catalonia** there was no detailed information available on components and the current load. If the network costs per MWh of produced power for distributed solar calculated above are used for Catalonia, the required investments in the electricity grid would be €0.36 billion, the annual costs (depreciation and operation and maintenance (O&M) costs €14 million per year).[24]

23 See Annex 1 for details on the calculations

24 Even though costs for improvement of the network are relatively low, temporal bottlenecks might occur when DSPV is installed over a short period, the network improvement will also have to take place within this short timeframe.

THE IMPACT OF DSPV ON THE (AVOIDED) INVESTMENTS AND COSTS OF ELECTRICITY GENERATION

Adding DSPV to the system will have an impact on other power generation assets and the total aggregated system costs. This could lead to the avoidance of upgrades to or construction of new power plants and associated costs, avoided expenditures on operation and maintenance of central power plants and avoided fuel costs.

In the sections below, we compare the difference in investments, O&M costs and fuel costs between the DSPV and the No Additional PV case. In total, 17 GW of solar PV is added in the DSPV case between now and 2030, whereas in de No Additional PV case, no additional PV is assumed to be added.

Aggregated investments

An estimated €22 billion is invested in solar PV until 2030 in the DSPV case. In the DSPV case, around €400 million less is invested in natural gas power generation between now and 2030 compared to the No Additional PV case.[25] [26] The avoided investments in gas capacity in the DSPV case are relatively minor compared to the additional investments in PV because flexible capacity is required in systems with intermittent power generation. This is included in the assessment.

Why does the avoided gas capacity in the DSPV case not equal the increase of solar PV capacity?

The avoided investments in thermal gas power capacity in the DSPV case are relatively small compared to the additional investments in PV. This is because flexible capacity is required in systems with intermittent power generation (to provide power in case of little wind or solar), a service that natural gas powered plants are technically very capable of delivering.

Whereas gas plants in the No Additional PV case run at a capacity factor of 50%, gas plants in the DSPV case run at a capacity factor of around 40%. An important reason for this is the fact that without further demand side management measures, demand peak does not always occur at the same moment as peaks in solar PV and wind production. This is illustrated in Figure 3.1, where production and demand in weeks in February and June in 2030 are compared: Gas plants are producing more power in February to cover lows in solar PV and wind production as well as peaks in electricity demand, wheres wind, solar PV and batteries can cover the lion's share of electricity demand in the shown week in June. Because the required gas capacity in an power system is determined by the peaks, avoided gas powered capacity is smaller than the increase in solar PV capacity.

25 Costs are calculated with current solar PV costs, whereas they are anticipated to decrease with about 30% in 2030. This means total cost could even be lower, while most benefits (e.g. avoided cost of CCGT power generation) are not expected to decrease. We applied current costs to show that under current prices, PV already provides value to the power system.

26 The No Additional PV case has 720 MW more CCGT. This means that in the DSPV case, the government pays €3 million less in to utilities in the capacity remuneration mechanism.

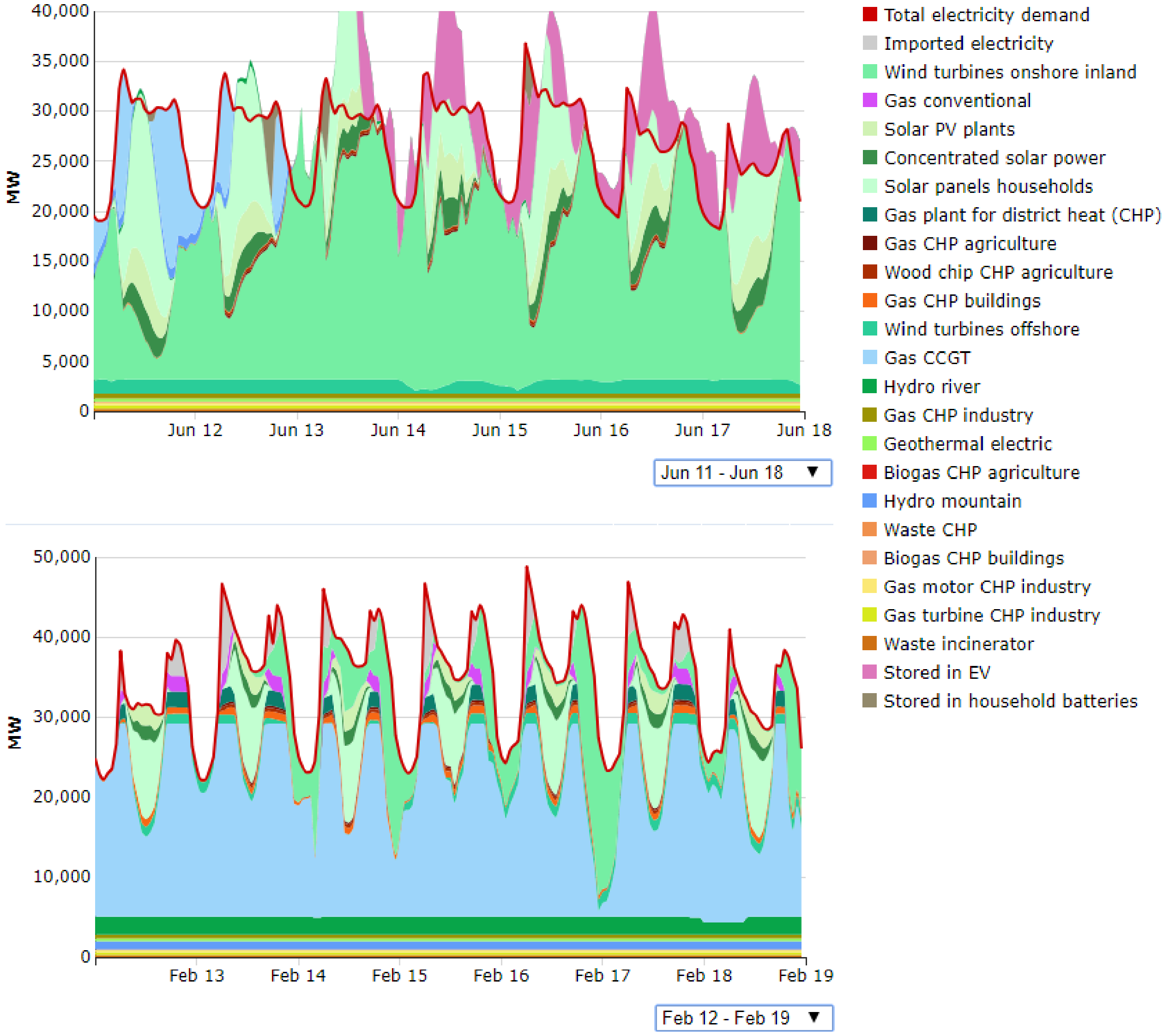

Figure 3.1 Electricity production per hour in the week between 11 and 18 June (top) 12 and 19 February (bottom), when annual electricity demand peaks, taken from the ETM (see links in Annex 4). The ETM calculates the hourly supply of electricity from the hourly demand and the installed capacities of all electricity producers. The order in which the producers are dispatched is determined by the merit order. Variable electricity producers as well as must-run technologies are not included in the merit order calculation. This chart shows the hourly production of electricity and gives a visual clue of the electricity generation mix. The graph shows that Gas CCGT produces a substantial share of the total power production in February, whereas in June wind and solar power production can cover total demand and batteries store excess power production.[27]

27 The CHP categories indicate the heat demand curve it follows, not necessarily the location of CHP. In the analyzed cases, heat from CHP is hardly used in households (e.g. there is a very small number of houses connected district heating), but it is applied in larger buildings, e.g. hospitals and public buildings.

Some existing US value of solar studies report higher avoided capacity investments estimations (e.g. Rocky Mountain Institute 2017). There are multiple explanations for this, for example: not all studies applied a full year analysis and some used capacity displacement factors while this study uses a scenario approach with a full year simulation. Furthermore, the correlation between demand and solar PV production differs from region to region. For example, in Spain, the peak in demand happens in February, whereas solar PV supply peaks in summer. Also, at lower penetration levels of solar PV, more conventional capacity is displaced per added unit of PV, thus impacting the size of avoided investments and in the DSPV scenarios penetration levels are relatively high. The avoided investments could be increased by adding cross-border import capacity or long-term electricity storage capacity, reducing the need for gas power capacity to cover peaks in demand and lows in solar PV or wind power production. See box 2 on page 28 for more details on the differences between the approach adopted in this study and those applied in US studies.

Annual cost of electricity generation

Table 3.1 shows the annual cost breakdown of electricity generation in the two cases: DSPV versus No Additional PV. Total operation and maintenance costs for the Spanish energy system are estimated to be slightly higher in the DSPV case, about €200 million more in 2030 compared to the No Additional PV case.

Whereas total investments and O&M costs are higher in the DSPV case, fuel savings are substantial, saving more than €1 billion in 2030 compared to the No Additional PV case.

Consequently, the total aggregated system costs of electricity generation in 2030 in the DSPV case is comparable to the system costs of the No Additional PV case.

If CO_2 emissions allowances would be included in the equation, the costs for the No Additional PV case would slightly exceed the costs for the DSPV case. Assuming a CO_2 price of €25/tCO_2 would add €250 million to the annual cost of power generation in the No Additional PV case.[28]

Table 3.1 Overview of total system costs and breakdown of electricity generation in the DSPV and No Additional PV case in 2030. Figures are rounded.

	DSPV 2030	No additional PV 2030
Cost of capital	€7.0 bln	€6.6 bln
Depreciation	€5.3 bln	€4.4 bln
Operation & maintenance cost	€3.2 bln	€3.0 bln
Fuel cost	€5.7 bln	€7.1 bln
Imported Electricity	€0.6 bln	€0.7 bln
Total without CO_2 emission allowances	€21.3 bl	€21.2 bln
CO_2 emission allowances	€ 0.9 bln	€1.1 bln
Total with CO_2 emission allowances	€22.2 bln	€22.3 bln

28 The IEA World Energy Outlook 2017 estimated the CO_2 price in Europe to be \$25/ tCO_2 in 2025 and \$41/ tCO_2 in 2040. IEA (2017a).

ENVIRONMENTAL BENEFITS

The environmental value of DSPV is positive when DSPV results in the reduction of environmental or health impacts that would otherwise have occurred (Rocky Mountain Institute 2017). This study looks at the main greenhouse gases (GHGs): CO_2, CH_4, N_2O.

Here we compare the emissions in the DSPV case with the No additional PV case heavily relying on power generation from thermal power plants (natural gas). Adding nearly 17 GW PV (the Distributed PV case) could mitigate an annual **10 $MtCO_2$-eq of GHG emissions by 2030,** because power generation from natural gas is reduced.[29,30]

Costs of solar PV installations have reduced quickly which means that the levelised cost of PV and thermal power generation are converging: €55/MWh for solar PV and €54/MWh for natural gas power generation.[31] Consequently, abatement costs also reduce quickly.[32]

29 Particulate matter (PM) emissions from natural gas are only estimated to be a few tonnes, so with natural gas as a reference, the impact on PM emissions is limited, but will be larger if coal power is being displaced by solar PV power generation.

30 The impact when comparing the two cases is smaller than the reader might expect because coal power is already phased out in the No Additional PV case.

31 Based on 2030 gas prices in the IEA World Outlook 2017 NPS. Levelised cost for large scale PV are estimated to be €37/MWh.

32 Abatement costs reflect the costs of an emissions abatement measure per tonne of abated GHG. Exact abatement costs depend on whether we take into account the fact that natural gas capacity will run at a lower capacity factor when there is tea higher share of variable renewables. Based on the total costs (including capital and fixed O&M costs) of distributed solar PV and gas power, abatement costs would be €1.4/tCO_2 and when comparing levelised costs of solar PV with the marginal costs of natural gas power production (i.e. fuel plus variable O&M costs, so assuming solar PV mainly replaces gas power production, but not capacity), abatement costs will be €45/tCO_2. When using large scale PV, abatement costs reduce to a range between €-28/tCO_2 and €8/tCO_2. Levelised costs are calculated under today's costs, whereas further reductions are expected: by 2030 a 30% reduction is projected. Source: Agora energiewende/Fraunhofer ISI, 2015. Current and Future Cost of Photovoltaics.

TOWARDS A VALUE OF SOLAR IN SPAIN

The deployment of distributed solar PV requires expenditures in operation and maintenance (O&M) as well as investments in the physical network . On the other hand, it may have multiple benefits. In the previous paragraphs the relevant cost/benefit categories have been assessed individually. To arrive at an aggregated net value for DSPV, the costs and benefits are levelised and aggregated. Levelising refers to dividing the total (avoided) costs (including capital costs and interest rates) over the power production from a generation technology over its lifetime. In this case, this means also distributing the avoided costs over the total additional DSPV generation[33]. The results of this exercise are presented in the figure and further detailed below.

The left column in Figure 3.2 represents the gross value of solar per additional MWh of distributed solar PV (compared to the No Additional PV case where natural gas is the dominant source of power generation). Because we study a system where PV is connected to the grid, we calculate avoided and network costs for the aggregate of self-consumed electricity and excess electricity fed into the grid. The most substantial contribution to the value of solar is associated with fuel savings: about €40/MWh. These avoided fuel costs consist partly of saved network losses (see section 2.4), representing €4/MWh, 10% of the avoided fuel costs.

In addition to this, adding DSPV to the system will have an impact on other power generation assets and the total aggregated system costs, but to a much lesser extent compared potential

33 See section 2.2. and Annex 3 – Financial analysis for an explanation of levelised costs.

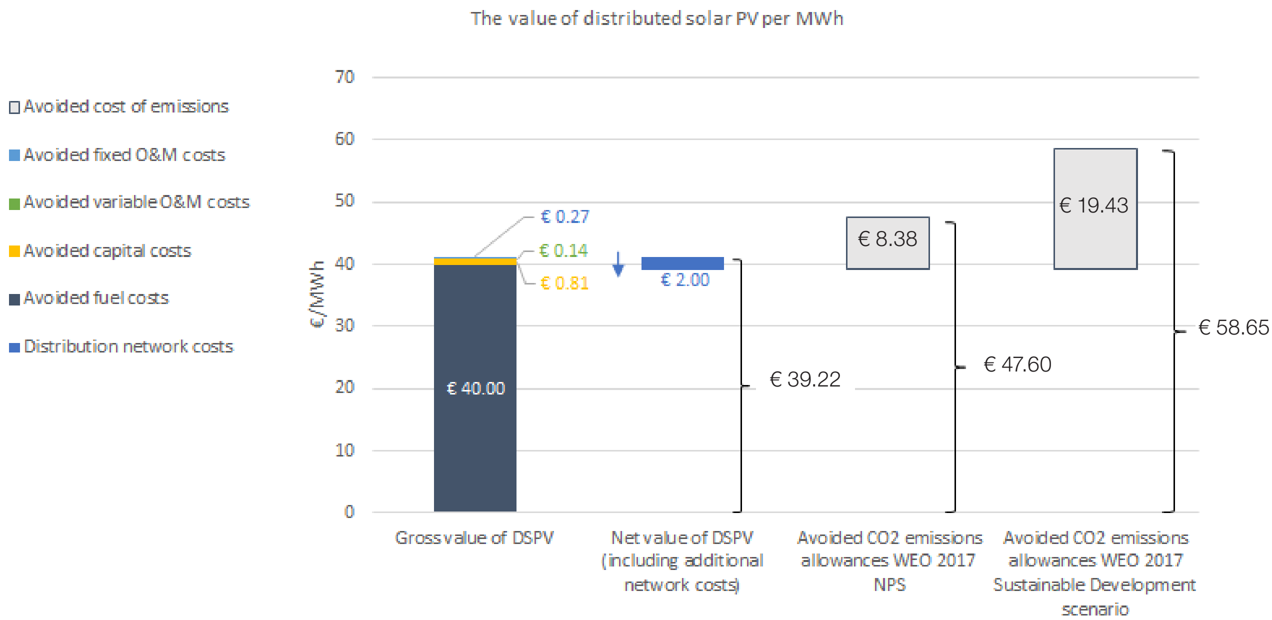

Figure 3.2 The value of solar PV in Spain of DSPV compared to the No Additional PV case (expressed in EUR/MWh). The avoided costs are composed of additional levelised network costs and the avoided levelised capital, O&M and fuel costs. Next to this, estimated avoided costs of emissions allowances under different scenarios from the International Energy Agency (IEA) are presented.

fuel cost savings.[34] The avoidance of upgrades to or construction of new power plants and associated capital costs have an estimated value of € 0.81/MWh, the avoided fixed and variable costs for operation and maintenance of central power plants are €0.27 MWh and €0.15/MWh respectively.

Besides having benefits and adding positive value to the Spanish power system, DSPV will have an impact on the transmission and distribution (T&D) infrastructure. Connecting high shares of DSPV to the electricity network will require additional network investments. The DSPV case requires about €2.0/MWh of additional investment compared to the No Additional PV case. This is represented in the second bar in Figure 3.2. The network costs associated with additional distributed solar PV are relatively small compared to the benefits.[35]

34 The results of this study show that the difference in investments in gas capacity between the DSPV and No Additional PV cases is smaller than the additional investments in solar PV in the DSPV case because significant gas power capacity is still needed for balancing, as explained in Box 1.

35 Network reinforcements will likely be necessary the coming decades to accommodate for example higher electrification levels of vehicles. This might reduce the additional investments that are needed to adjust the grid for higher DSPV penetration rates.

When subtracting the costs of network investments from the benefits, **we arrive at a net positive value for DSPV in Spain of around €39/MWh.** This does not yet include the value of avoided emissions. The figure therefore also shows the potential avoided costs for CO_2 allowances in two scenarios in 2030: the WEO 2017 NPS and the WEO 2017 Sustainable Development scenario. When including the monetary value of avoided emissions into the equation, the net value becomes even more positive: between €48/MWh and €59/MWh, respectively.[36][37]

36 The IEA World Energy Outlook 2017 New Policies Scenario models the impact implemented and announced policies until 2040. The Sustainable Development Scenario (SDS) models developments towards a future that is consistent with the objectives of the Paris Agreement, universal access to modern energy and the objective to improve air quality by reducing non-GHG energy-related pollutants. Where the NPS models the impact of current and announced policies, the Sustainable Development scenario starts with future objectives and develops a pathway backwards. Because lower emissions will be achieved in the Sustainable Development scenarios, measures with higher marginal abatement costs have to be implemented, requiring/resulting in higher prices of emissions allowances. Estimating from a linear interpolation between the values provided for 2025 and 2040, the emissions allowance price in 2030 are €25/tCO_2 in the NPS and €58/tCO_2 in the SDS. IEA (2017a)

37 Avoided costs could also include the social and environmental costs associated with carbon emissions. These cost estimations have a very wide range. For example Nordhaus (2016) collected social costs of carbon range between about \$30/tCO_2 and more than \$300/tCO_2, depending on a wide range of assumptions. Nordhaus (2016). This would translate to a range of €9/MWh and over €80/MWh of avoided social cost of carbon. Nordhaus (2016). Revisiting the social cost of carbon. PNAS, February 14, 2017, vol. 114, no. 7.

Key differences between the approach adapted in this study and the Value of Solar studies performed in the US

This is the first time the Value of Solar approach is applied in Europe. There are differences between the outcomes of the US studies and between those and this study, This is partly due to differences in applied methodology and partly due to inherent regional differences. Regarding methodologies, studies include different cost and benefit categories, some more, some less and there are differences in input data and the way VoS is calculated. This study is based on the detailed modelling of the impact of distributed solar PV on the electricity grid, while most US studies do not and often assume certain parameters including capacity factors and marginal resource allocation and generation plant displacements etc. Also, not all US studies have applied a full year analysis as this study does. Regarding regional differences: the value of solar is determined to a large extent by regional characteristics that may include differences in fuel prices (e.g. natural gas prices are higher in Europe), solar irradiation, differences in network topology, capacities and load, differences in supply and demand patterns, power plant efficiencies etc.

THE FINANCIAL IMPACT OF DISTRIBUTED SOLAR PV ON STAKEHOLDERS

This chapter examines the direct financial impacts of deploying DSPV on a large scale, for the different stakeholders involved. Firstly, the financial effects of DSPV under the current tariff regime is examined for two types of installations (2 kW and 15 kW) and for two cases, with and without remuneration of electricity. Secondly, this chapter explores the impact of two measures and assesses what ***would*** happen if a) there would be ***no*** transitory charge on self-consumed electricity and b) there is higher remuneration for surplus of electricity. In Spain, these impacts will differ from region to region, mainly as a result of different electricity demand in those regions. The financial impact on stakeholders is assessed for two Spanish regions: Catalonia and Andalusia.

Payback periods of investments in solar PV provide an indication of the attractiveness to invest for households and businesses. In this study, payback periods are calculated for three types of household tariffs (2.0A) as well as for small and medium sized enterprises (SMEs, 3.0A).

This study also calculates the financial effects of DSPV on the income of both the government and system operator, both for the current situation (with and without remuneration) and for the fictive cases where the transitory charge on self-consumed electricity is cancelled (with two levels of remuneration of surplus electricity).

PAYBACK PERIODS FOR INVESTMENTS IN DSPV

This section shows the payback periods of investments in distributed solar PV under the current tariff structure. We consider two cases: one in which customers waive remuneration and one in which the excess electricity fed into the grid is remunerated with €0.04/kWh[38].

Payback periods under the current tariff regime

In this study it is assumed that on average, 2 kW of solar PV is installed by households and 15 kW PV is installed by SMEs. Table 4.1 shows the amount of self consumption and surplus electricity for the different stakeholders examined. In this study, it is assumed that in the DSPV case, solar PV is distributed evenly over the consumers in the four groups that are examined. This means a high penetration of DSPV, roughly 40% of the consumers have a PV system installed. In ETM-SA both the consumption and the production were modelled (consumption is modelled as total consumption distributed with the corresponding profile, production is modelled using the capacity of DSPV installed and solar irradiation[39]). The analysis showed that, depending on the stakeholder and region, between 24% and 77% of the generated electricity is self-consumed. Table 4.2 shows that the total value of electricity produced by DSPV is between M€300 and M€470 in Andalusia and between M€260 and M€410 in Catalonia.

38 This is a net remuneration of surplus electricity. This remuneration is based on the average electricity market price for the free market in 2016 (€0.047/kWh, Red electrica de espana (2018)) and the average electricity market price for 2030 in the DSPV case (€0.042/kWh, see ETM scenario). The value that is used for net remuneration (€0.04) is lower than thes market prices because generation charge is not included.

39 For details on the profiles used see Annex 1

Table 4.1 Average amount of self consumed and surplus of electricity for the different user groups in Andalusia and Catalonia for 2 kWp PV of households and 15 kWp PV of SMEs during a year and the total for the region

	Andalusia		Catalonia	
	Self consumption [kWh]	**Surplus electricity [kWh]**	**Self consumption [kWh]**	**Surplus electricity [kWh]**
Households - Type Bono social	900	2,800	1,000	2,700
Households - Type PVPC	1,300	2,400	1,100	2,600
Households - Type Mercado libre	1,600	2,100	1,300	2400
SMEs	18,900	7,800	20,500	6,200
Total for region	3,200,000,000	4,700,000,000	2,800,000,000	4,200,000,000

Table 4.2 Total value of self consumption, surplus of electricity and total production in Andalusia and Catalonia with various VOS

	Andalusia			Catalonia		
	Value with VOS €39/ MWh [M€]	**Value with VOS €48/ MWh [M€]**	**Value with VOS €59/ MWh [€]**	**Value with VOS €39/ MWh [M€]**	**Value with VOS €48/ MWh [M€]**	**Value with VOS €59/ MWh [M€]**
Self consumption	120	150	190	100	130	160
Surplus	180	230	280	160	200	250
Total	300	380	470	260	330	410

We first consider a realistic case where households and SMEs install DSPV and waive remuneration. In that case, both households and SMEs are type 1 consumers. Households do not pay transitory charge on self-consumed electricity, SMEs do pay transitory charge on self-consumed electricity. Under these circumstances the payback period is unattractive for all customers: between 10 and 25 years.

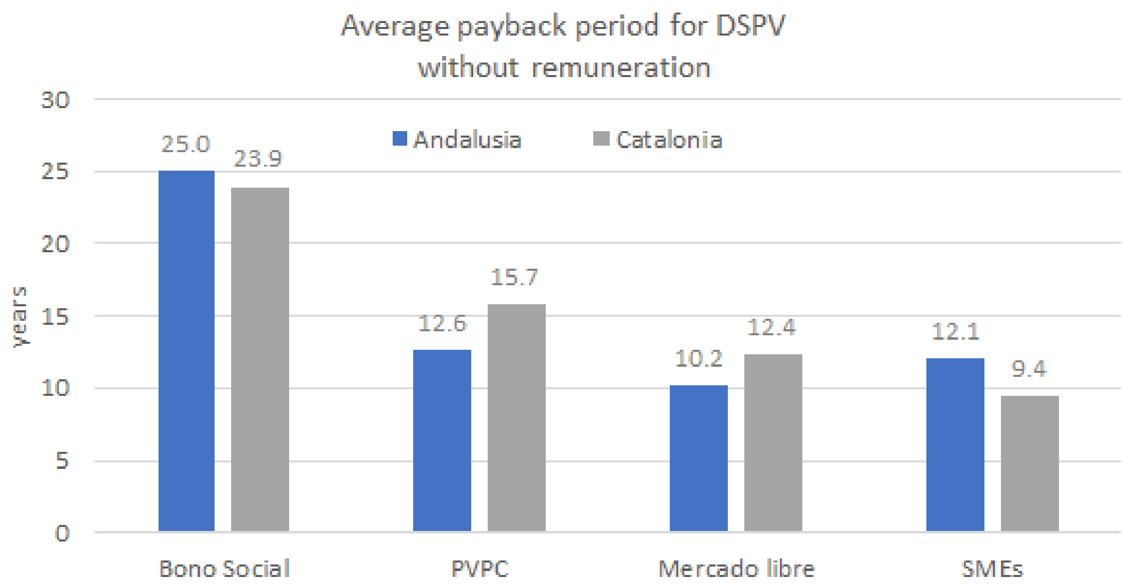

Figure 4.1 Payback periods for 2 kWp PV installations (households - for the three types) and 15 kWp PV installations (SMEs) under the current tariff regime for the case where surplus electricity is not remunerated. SMEs pay transitory charge on self-consumed electricity, households do not pay transitory charge on self-consumed electricity.

In the current system it is very complex for customers with installations < 100 kWp to receive remuneration for surplus of electricity. They have to register as an electricity producing business and comply to the same requirements as any supplier of electricity. So the case in which households and SME receive remuneration for surplus of electricity (and all pay transitory charge on self-consumed electricity) is highly theoretical. Under the current tariff regime payback periods are lower when the customers receive remuneration. But, the payback periods can still be considered long: between 9 and 16 years.

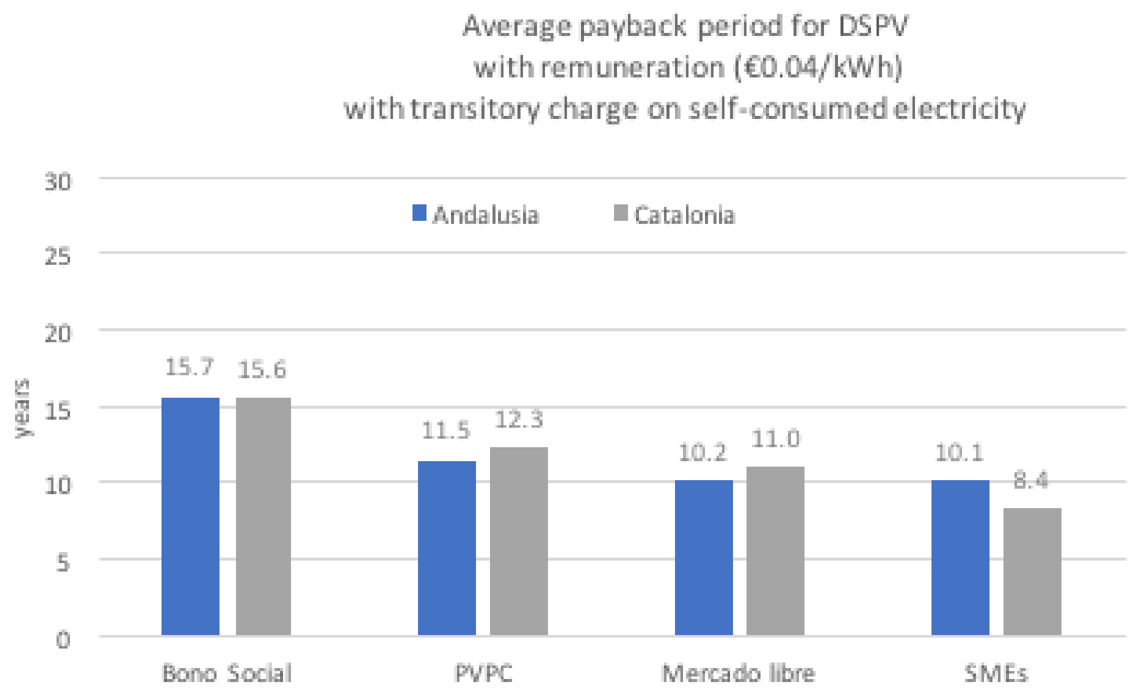

Figure 4.2 Payback periods for 2 kWp PV installations (households - for the three types) and 15 kWp PV installations (SMEs) under the current tariff regime for the case where surplus electricity is remunerated. Households and SMEs all pay transitory charge on self-consumed electricity.

Payback period under an alternative regime

Investing in DSPV is not beneficial for any of the examined consumer groups under the current tariff regime. What will happen to the payback periods of investmenting in PV if the transitory charge on self-consumed electricity is cancelled? The figure below shows the payback periods for the case where customers receive a net remuneration of €0.04/kWh and where the transitory charge on self-consumed electricity is cancelled. This decreases the payback periods significantly.

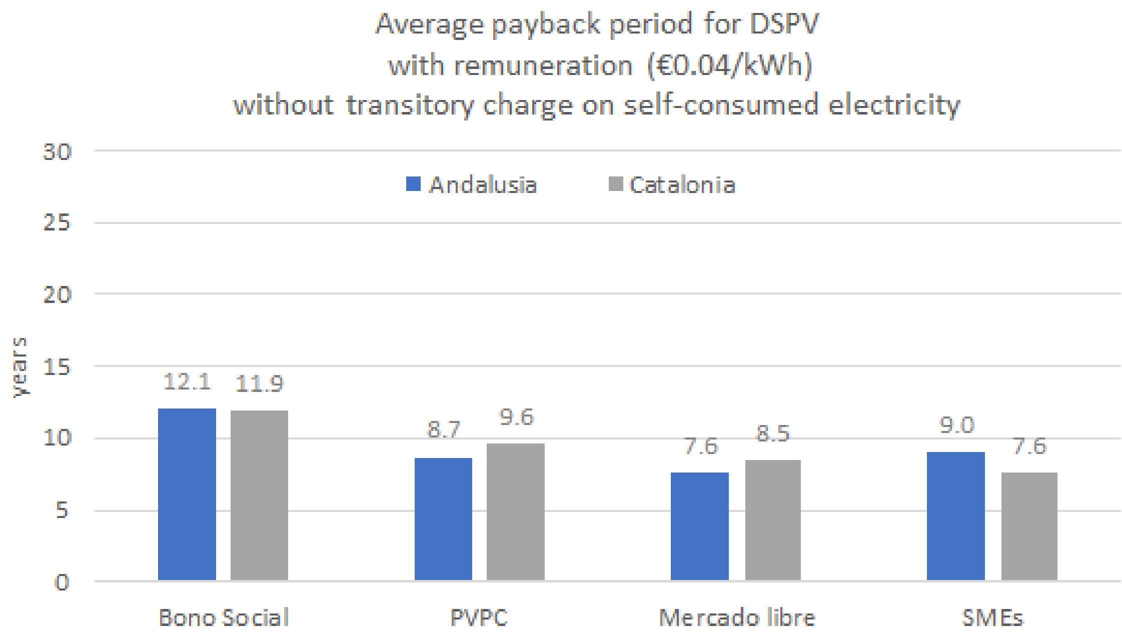

Figure 4.3 Payback periods for 2 kWp PV installations (households - for the three types) and 15 kWp PV installations (SMEs) when surplus electricity is remunerated with €0.04/kWh and the transitory charge on self-consumed electricity is cancelled.

When the transitory charge on self-consumed electricity is cancelled, payback-periods are between 7.5 and 12 years. A payback period of 7.5 years can be considered attractive, but some consumers still have higher payback periods than that and will need a higher remuneration to make investment in DSPV attractive. This applies specifically to vulnerable consumers (bono social). Considering that the value of DSPV in Spain (€0.048/kWh with low environmental costs, €0.059/kWh with high environmental costs) is higher than the spot price, it could be considered fair to give additional rewards to customers with DSPV. There are several option to organise such a reward, for example:

- Remuneration for all electricity that is produced by PV;
- Extra remuneration of surplus of electricity;
- Investment subsidies.

Figure 4.4 shows the payback periods for the case where customers receive a net remuneration for their surplus electricity of €0.10/kWh. This remuneration is roughly equal to the spot price + the value of solar assuming high environmental costs. With this remuneration the payback period becomes between 5.5 and 7 years for households. For SMEs the payback period is between 6.5 and 7.5 years. Because SMEs have a relative higher self-consumption, they benefit less from a remuneration surplus than households do.

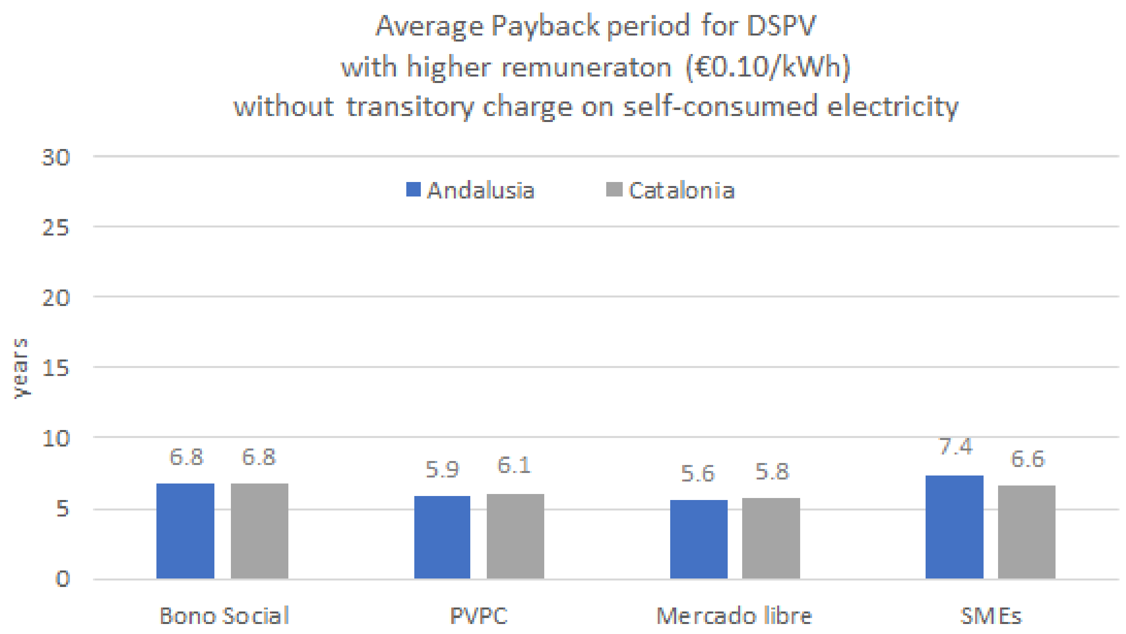

Figure 4.4 Payback periods for 2 kWp PV installations (households - for the three types) and 15 kWp PV installations (SMEs) in when surplus electricity is remunerated with €0.10/kWh and the transitory charge on self-consumed electricity is cancelled.

In the Spanish case, for most stakeholders remunerating surplus electricity with the spot price results in sufficiently short payback periods. However, in locations where electricity prices or where solar radiation are lower customers will require additional monetary incentives.

THE FINANCIAL EFFECTS OF DSPV FOR THE GOVERNMENT AND SYSTEM OPERATORS

The income and revenue of both the government and system operator may be affected by the deployment of DSPV, depending on the tariff levels and structure in place. In this section, the financial impact on these stakeholders is assessed under a) the current tariff regime without remuneration, b) the current tariff regime with remuneration and c) a regime where the surplus of electricity is remunerated and the 'Transitory charge on self-consumed electricity' is cancelled.

When DSPV is installed, the electricity bill of households decreases relative to a case with no DSPV. This is caused by reduced electricity consumption from the grid and implies, just like any other reduction due to energy savings, a reduction in payments to three parties: government, system operator and the supplier.

The levelised change in income of the government from households and SMEs differs from the No Additional PV case when there is a high penetration of DSPV (40% of households and SMEs have PV installed). The levelised income difference represents the change in income relative to the No Additional PV case, divided by the total additional electricity production from DSPV. The income of the government decreases with roughly €12/MWh of DSPV. A significant part of the lost income of the government will be compensated by the VAT that from investments in DSPV. With a PV system lifetime of 25 years and 21% VAT, the government receives €5 euro/MWh from DSPV. In addition, if prosumers would have to pay 21% VAT on injected electricity sold to the grid as well as 7% electricity tax, the government would receive an additional €7-8/MWh. These taxes are not taken into consideration for the calculation of the payback periods, because this report does not assess nor wishes to propose a specific remuneration system (therefore it is referred to as net-remuneration). Including these taxes would result in more income for the government but also in longer payback periods.

Figure 4.6 below shows how the income of the system operator from households and SMEs differs from the No Additional PV case when there is a high penetration of DSPV (40% of households and SMEs have PV installed). With the current tariff structure, without remuneration (and only SMEs pay transitory charge on self-consumed electricity), the income of the system operator drops with roughly €12/MWh. Under this calculation charges paid by prosumers on the injected electricity (0.05€/MWh) will result in the same income as charges paid by other producers in the No additional DSPV scenario, therefore these are not included. If, also under the current tariff structure customers would receive remuneration (and pay the transitory charge on self-consumed electricity), the income of the system operator increases with €4/MWh compared to the No Additional PV case. This increase of income is higher than the additional network costs of €2/MWh. Cancelling the transitory charge on self-consumed electricity results in a reduction of income of the system operator of around €14/MWh. The income of the system operator increases with €4/MWh compared to the No Additional PV case. Maintaining the transitory charge will thus lead to around €16-19/MWh (depending on the region) more income for the system operator, compared to a situation without the charge. And maintaining the charge would lead to the prosumer paying more to the system operator than the additional network costs to integrate DSPV, at the expense of the attractiveness of SMEs investing in DSPV.

THE NET FINANCIAL EFFECTS OF DSPV

Figure 4.7 shows the costs and benefits of DSPV for various levels of remuneration of surplus electricity. In these calculations the 'Transitory charge on self-consumed electricity' is set to zero (cancelled)[40]. The loss of income include the reduction of income of the government and the system operator because of reduction of electricity that is consumed from the network, additional costs carried by the system operator and remuneration of surplus electricity[41]. The benefits consists of VAT that the government receives when solar PV systems are purchased. Furthermore the benefits consist of sales of surplus electricity to a third party42. Transactions between other stakeholders in the system (for example between fossil powered electricity producers and the government and system operator) are outside the scope of this study.

Figure 4.7 presents the net financial impact of DSPV with various levels of remuneration. The net financial impact varies between €23/MWh when surplus is remunerated with €0.04/kWh, and €53/MWh when surplus is remunerated with €0.10/kWh. The range of this net financial impact is lower than the range of the value of solar: €39/MWh to €59/MWh.

40 In this figure the average values of the calculations for Andalusia and Catalonia are used.

41 It is not defined who pays the remuneration of surplus electricity, nor who receives the benefits when it is sold through. For the net financial effects of DSPV it is irrelevant which stakeholder is involved in buying and selling surplus electricity.

42 It is assumed that surplus electricity is sold for €0.04/kWh

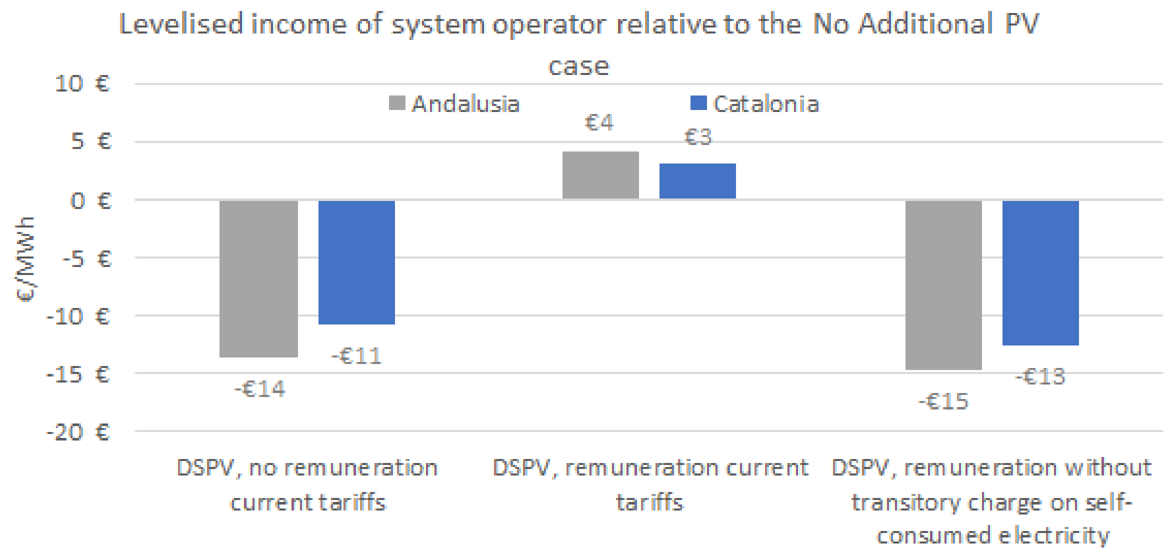

Figure 4.6 Financial consequences of DSPV for the system operator with respect to the No Additional PV case. Three tariff structures are shown: the current tariff regime with charge on self-consumed electricity and without remuneration, the current tariff regime with charge on self-consumed electricity and with remuneration and a regime where the surplus of electricity is remunerated and the 'Transitory charge on self-consumed electricity' is cancelled. This figure shows levelised change in income; the difference in income relative to the No Additional PV case is divided by the total electricity production from DSPV. In this figure only transactions from households and SMEs to the system operator have been taken into account.

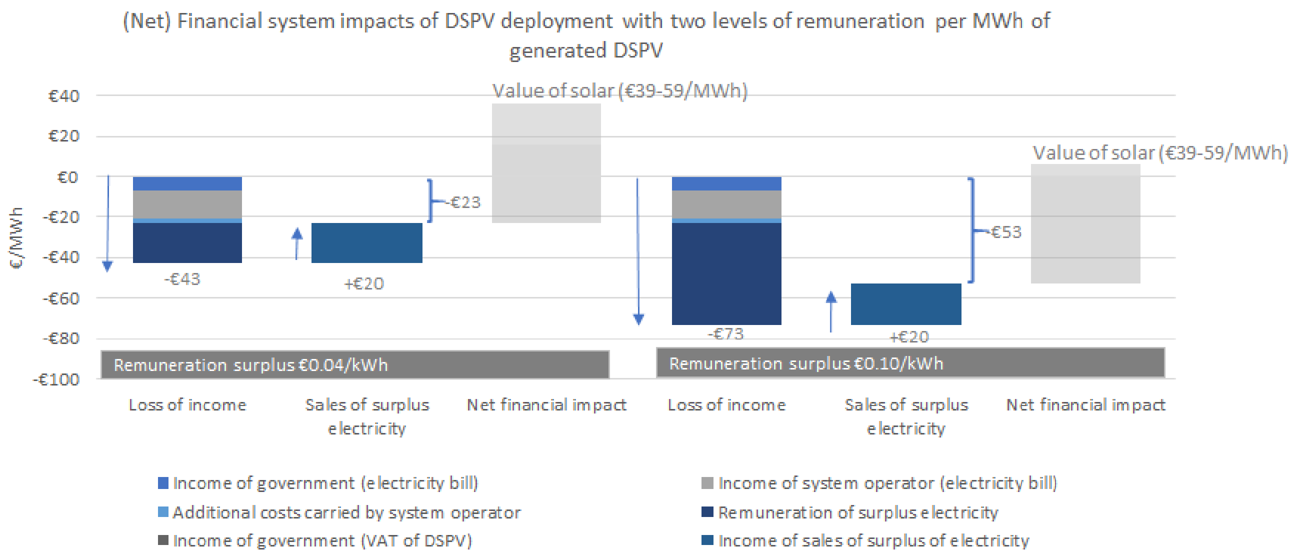

Figure 4.7 Net financial impact of DSPV with various levels of remuneration. Transitory charge on self-consumed electricity is set to zero (cancelled). Calculations are indicative, and the remuneration scheme is not defined: These calculations do not include possible VAT on sold electricity (21%) and electricity tax (7%).

CONCLUSIONS AND RECOMMENDATIONS

The results of this study show that distributed solar PV (DSPV) has a positive net value in Spain of around €39/MWh. This does not yet include the value of avoided greenhouse gas emissions. When including these into the equation, the net value becomes even more positive: between €48/MWh and €59/MWh. This is presented in figure 5.1 below.

In terms of **benefits**, the most substantial contribution to the value of solar is associated with fuel savings from natural gas plants that would otherwise have been needed to produce the power that is instead produced with distributed solar PV installations: about €40/MWh. In addition to this, adding DSPV to the system will have an impact on power generation assets and total aggregated system costs, but to a much lesser extent when compared to potential fuel cost savings. Because we study a system where PV is connected to the grid, we calculate avoided and network costs for both self-consumed electricity and electricity fed into the grid. Avoided upgrades or construction of new power plants and associated capital costs amount to €0.81/MWh. The avoided fixed and variable costs for operation and maintenance of central power plants have a value of €0.27/MWh and €0.15/MWh respectively.

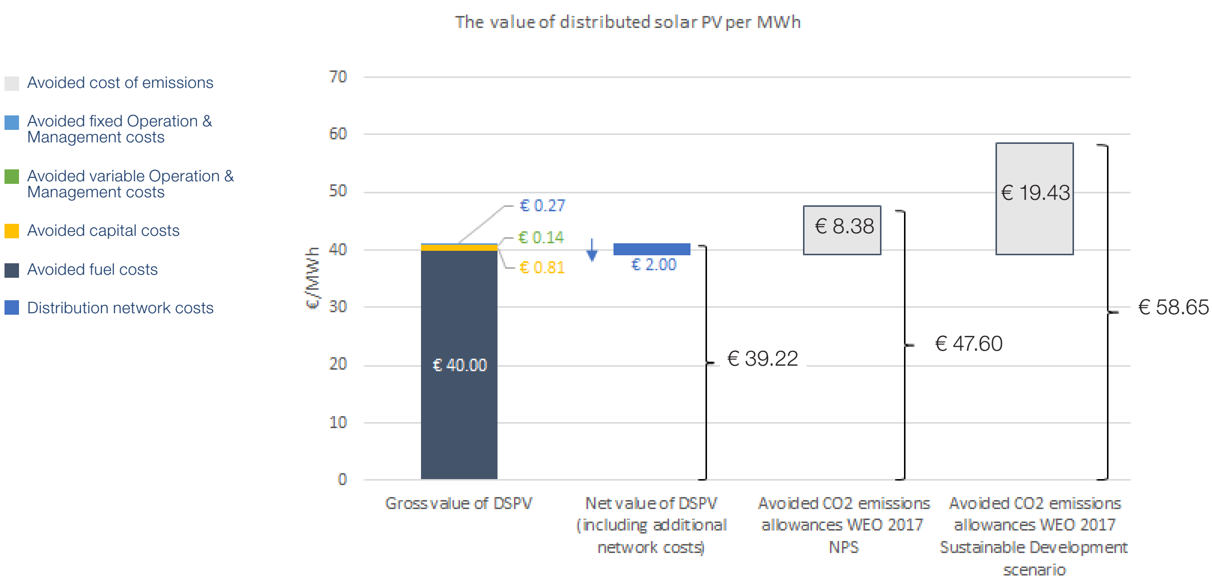

Figure 5.1 The value of solar PV in Spain: DSPV compared to the ‘no additional PV’ case (expressed in €/MWh). The avoided costs are composed of additional (levelised) network costs and the avoided (levelised) capital, operation & maintenance (O&M) costs and fuel costs. Next to this, the graph illustrates estimated avoided costs of emission allowances under different scenarios from the International Energy Agency (IEA). Because we study a system where PV is connected to the grid, we calculate avoided and network costs for both self-consumed electricity and excess electricity fed into the grid.

In terms of **costs**: besides having benefits, high penetration of DSPV will incur additional network investments. The DSPV case studies that were examined in this study require about €2.0/MWh of additional investment compared to the 'No Additional PV' case. This is illustrated in the second column in the figure 5.1. Network costs associated with additional distributed solar PV are relatively small compared to the benefits.

This study shows that investing in PV is unattractive for households and SMEs because of the current tariff regime. Payback periods for DSPV on households are 10 years or longer in both regions investigated (Andalusia and Catalonia).

Regarding **households**, in the current situation, investing in DSPV is unattractive. Payback periods are >10 years for all customer types. Remuneration of surplus electricity is possible, but very complicated and not very realistic in practice. And because households in that case have to pay the transitory charge on self-consumed electricity it does not result in attractive payback periods. **SMEs** always pay the transitory charge on self-consumed electricity because their installation is larger than 10 kWp. For them, with the current tariffs, the payback period is 9-12 years without, and 8.5-10 years with remuneration.

Cancelling the transitory charge on self-consumed electricity combined with some additional remuneration could make investments in DSPV a lot more attractive.

If the transitory charge on self-consumed electricity were cancelled, payback-periods would drop to a range of 7.5 to 12 years, depending on the type of customer. A payback period of 7.5 years can be considered attractive, but some consumers still have longer payback periods and will need additional remuneration to make investments in DSPV attractive, especially for vulnerable customers (Bono Social).

A way to make investments in PV more attractive is to supply higher remuneration for electricity fed into the grid. If prosumers receive a net remuneration of surplus electricity of €0.10/kWh (this remuneration is roughly equal to the spot price plus the value of solar, assuming high environmental costs) the payback periods drop further: to 5 to 6 years for households and 6.5 to 7.5 years for SMEs. For most prosumers a lower remuneration would be sufficient to arrive at attractive enough payback periods.

Even in the case of high DSPV penetration (12% of share in the national power mix, 17 GW) the government and system operators are faced with only a moderate loss of income from their revenue streams.

For the **system operator**, the reduction of revenue (€14/MWh[43]) is more significant than the required investments associated with network enhancement (€2/MWh). In the hypothetical case where all households and SMEs choose to be remunerated for surplus electricity under current tariffs, they would all pay a transitory charge on self-consumed electricity. The income of the system operator would increase by a higher amount (€4/MWh) than the costs associated with network enhancement.

The reduction of revenue for the **government** in the DSPV case (€14/MWh) is of the same order of magnitude as the reduction of revenue the system operators are faced with.

43 In the situation where the transitory charge on self-consumed electricity is cancelled.

The current tariff regime for distributed solar PV in Spain does not properly reflect its costs and benefits.

This study shows that even if the value of avoided greenhouse gas emissions as a result of DSPV deployment is not included, the benefits far outweigh the incurred network costs, DSPV has a net positive value for the system of about €39/MWh. The current regime makes investments in distributed PV unattractive, with payback periods that are usually considered too long by both households and SMEs. This is reflected in the fact that in the last couple of years, hardly any self-consumption renewable systems connected to the grid have been installed in Spain. There are two important reasons for this. Firstly the surplus of electricity exported to the grid is currently often not remunerated for PV systems < 10kW. If it is remunerated, prosumers pay a transitory charge on self-consumed electricity. Systems > 10 kWp are always subjected to the 'Transitory charge on self-consumed electricity'.

Cancelling the transitory charge and introducing a net-remuneration for exported electricity at a level equal or around the current spot price for electricity (around €40/MWh), could make investments in DSPV sufficiently attractive for some households. SMEs and households with PVPC (regulated tariffs) will however need additional remuneration to make investments attractive enough. Considering that the value of DSPV in Spain (€0.048/kWh with low CO_2 allowance costs, €0.059/kWh with CO_2 allowance costs) is higher than the spot price, it is justified to provide extra rewards to customers with DSPV. There are several ways imaginable to structure this reward.

If surplus electricity were remunerated with €0.10/kWh (roughly equal to the spot price plus the value of solar, assuming high environmental costs), investing in DSPV becomes interesting for all prosumers examined in this study (pay-back period < 7.5 years).

When remuneration is taken into account, the net financial impact on the government and system operator will vary between €23/MWh, when surplus is remunerated with €0.04/kWh, and €53/MWh, when surplus is remunerated with €0.10/kWh. The range of this net financial impact is lower than the range of the value of solar: €39/MWh to €59/MWh.

In the Spanish case, for most stakeholders, remunerating surplus electricity with the spot price and cancelling the transitory charge on self-consumed electricity would result in sufficiently short payback periods. However, in locations where electricity prices are lower or where solar radiation is lower, customers may require additional remuneration. **It is recommended that any future design of tariff structures for distributed solar PV properly reflects both the benefits, as well as the costs of distributed solar PV.**

The value of solar is highly positive for the Spanish electricity system and society overall and the benefits far outweigh the costs. There is thus a rationale for providing a fair remuneration for surplus electricity from DSPV systems exported to the grid. This should be combined with tariffs that allow for a reasonable distribution of costs incurred on the electricity network and the potential loss of income for the government. Because distributed solar delivers benefits for society as a whole, households and SMEs that have an interest to invest can not be blamed for the reduction of the system income due to a reduction in electricity consumption. Rather, the challenge is to design an adequate system that allocates costs and benefits to the different stakeholders in a balanced way.

While the situation is Spain is obviously unique and its tariff structure is different from other countries in the EU, we would expect the net value of distributed solar PV to be positive in most, if not all EU countries.

However, the value will be different in magnitude. The approach adopted in this study can be translated to other EU countries and thereby contribute further to the design of new electricity market regulation and the setting of tariffs and incentives for distributed solar PV systems that reflect benefits as well as costs.

To further develop the value of solar approach, it is crucial to have transparent and full access to grid and consumption data.

The regional administrations *(la Agencia Andaluza de la Energía* and the *Instituto Catalán de Energía)* have kindly cooperated to give access to their data. However, the available information and data was insufficient to calculate all avoided costs. The value of solar is therefore likely to be even higher. Many of the grid and consumption data is not available, not even to regional energy agencies. The EU and national governments should continue to improve their data gathering and transparency of retail market data and ensure that policy makers and stakeholders have access to the information.

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ANNEX 1
DETAILS OF ANALYSIS IN ETM-SA

This annex contains:

- Information on load profiles that were used in the analysis;
- Energy uses for different users in the regions in the present situation and in the future cases.

PROFILES

The time-resolved load on the network is a combination of annual load and a load profile. The profiles have a time resolution of one hour.

*Source:
e.sios: https://www.esios.ree.es/es generacion-y-consumo*

- Profile for transportation network: E6 (>220 kV)
- Profile for distribution network HV: E3+E4+E5 (36 kV to 220 kV)
- Profile for distribution network MV: E1+E2 (1 kV to 36 kV)
- Profile for distribution network LV other: E0 (<1 kV total) minus E0 (<1 kV <10 kW)
- Profile for distribution network households: E0 (<1 kV <10kW)
- Profile for tariff 3.0A: Tarifa De Acceso 3.0A

The solar profile that is used to model the time-resolve generation of PV is based on data supplied by SoDa.

*(Solar Radiation Data Service.
http://www.soda-pro.com/home).*

ANNUAL DEMANDS IN ETM-SA

For Andalusia and Catalonia the total demand per voltage level is known for 2015. The ETM cases for Spain are used to scale the present demand of all voltages levels of the two provinces and compose the 2030 cases in ETM-SA.

Andalusia

Table A.1 Annual demands per user group in Andalusia.

	Present		2030	
	Demand per connection [kWh]	Number of connections [-]	Demand per connection [kWh]	Number of connections [-]
HV user	20,136,176	324	18,304,039	324
MV user	531,276	16,040	482,937	16,040
Bono social	1,835	517,414	1,855	546,070
PVPC	2,890	2,093,424	2,921	2,209,363
Mercado libre	3,469	1,739,957	3,507	1,836,320
LV user other	9,987	620,599	5,111	654,969
SMEs[44]	48,372	16,040	43,970	16,040

Source: https://www.agenciaandaluzadelaenergia.es/es/documentacion/tipo-de-documento/informes-y-estudios/caracterizacion-del-suministro-de-energia-electrica-en-andalucia

44 Solar Radiation Data Service. http://www.soda-pro.com/home

Catalonia

Table A.2 Annual demands per user group in Catalonia.

	Present		2030	
	Demand per connection [kWh]	Number of connections [-]	Demand per connection [kWh]	Number of connections [-]
HV user	5,569,413	1,857	5,062,667	1,857
MV user	2,826,937	4,033	2,569,722	4,033
Bono social	1,927	233,281	1,947	246,201
PVPC	2,236	1,539,468	2,260	1,624,728
Mercado libre	2,749	2,083,338	2,779	2,198,718
LV user other	18,822	553,523	9,633	584,178
SMEs[45]	55,092	150,346	50,079	150,346

Sources:
Electricity use of main groups: Comisión Nacional de los Mercados y la Competencia (CNMC) https://www.cnmc.es/expedientes/isde04117
Subgroups tarif 2.1A: Institut Català d'Energia (ICAEN)46
Electricity consumption per sector: Generalitat de Cataluya, Institut d'Estadística de Catalunya: http://www.idescat.cat/pub/?id=aec&n=504&lang=en

45 Used only for financial analysis, in the network calculation SMEs are part of the MV user group.

46 Information used of energy usage for consumers connected to the main DSO in Catalonia (ENDESA DISTRIBUCIÓN), which represents about 95% of total electricity demand.

PEAK DEMANDS

The capacity charge of tariff 3.0A depends on the capacity and the period. The combination of demand, the profile used and the installed PV results in the following peak demands.

Table A.3 Peak demands (and in DSPV case absolute maximum of peak demand and peak production) of SME connections. This is used in the financial calculations as the tariffs for these groups are capacity dependent.

	Andalusia		Catalonia	
	Maximum network consumption (no additional PV) [kW]	**Maximum network consumption / production (DSPV) [kW]**	**Maximum network consumption (no additional PV) [kW]**	**Maximum network consumption / production (DSPV) [kW]**
Period 1	7.7	7.7	8.7	8.7
Period 2	8.8	8.6	10.0	8.1
Period 3	6.6	10.4	7.5	9.8

ANNEX 2

DETAILS OF CALCULATIONS TO ESTABLISH THE REQUIRED INVESTMENTS IN THE ELECTRICITY NETWORK

This annex provides information on all the steps of the calculations of the required investments in the electricity network as a result of DSPV. The definition the network topology, profiles and annual demands in ETM-SA, the determination of the current replacement value of the electricity network, the changes in (average) load on network and the additional network investments required for the case with DSPV.

- The lay-out of the network topology used in the analysis;
- How value of current grid is determined;
- How the average load on the grid changes in the modelled cases;
- How extra investments are determined.[47]

NETWORK TOPOLOGY

The network is modelled following a layout consisting of four voltage levels. To determine the time resolved load on these voltage levels, corresponding load profiles are used.

47 For analysis of impact on network local assets have been assessed. For this study, only general information was available. Therefore, the impact on network is estimated using a study performed by system operators in The Netherlands

In ETM-SA the grid is defined in four voltage levels:

- Transportation network
- Distribution network - HV
- Distribution network - MV
- Distribution network - LV

Load can be attached to each voltage level. For the LV-level three types of users are defined:

- Bono Social
- PVPC
- Mercado Libre
- LV user other

The figure below schematically shows how the network is modelled

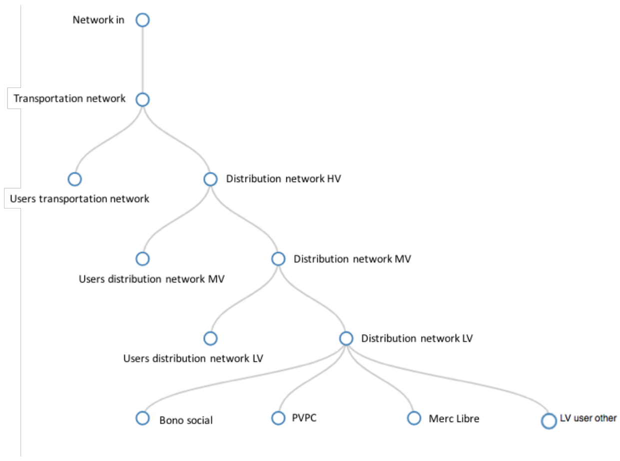

Figure A.1 Topology used to model the electricity network of Andalusia in ETM-SA.

CURRENT REPLACEMENT VALUE OF THE ELECTRICITY NETWORK

The network costs are determined by combining information on the amount and type of installed components with information on costs of these components. The current total value of the electricity grid is determined for both Andalusia.

Source installed network: http://www.agenciaandaluzadelaenergia.es/info-web/principalController#
Source costs transportation network: BOE-A-2015-13487
Source costs distribution network: BOE-A-2015-13488

Summary of total network

Assumptions:

- Transportation network consists of the complete transportation network
- Distribution network HV consists of AT lines, AT/AT transformers and subestaciones
- Distribution network MV consists of MT lines and AT/MT transformers
- Distribution network LV consists of distribution centers and LV lines

Table A.4 Current replacement value and annual operation and maintenance (O&M) costs of the electricity network in Andalusia.

	Current replacement costs	Current annual O&M costs
Transportation network	€ 3.9 bln	€ 0.13 bln
Distribution network (HV)	€ 19 bln	€ 0.69 bln
Distribution network (MV)	€ 4.1 bln	€ 0.15 bln
Distribution network (LV)	€6.3 blnn	€ 0.24 bln

Assumptions regarding the distribution network

- The average costs of all components in a category is used because there is no information available of the share of the components in the network
- Costs for medium voltage lines determined using the average costs of all Líneas aéreas with capacity above 36 kV
- Costs for medium voltage lines determined using the average costs of all Líneas aéreas with capacity between 1 kV and 36 kV
- Costs for substations are determined by using the average costs of all *Posiciones blindadas, Posiciones convencionales* and Posiciones híbridas with capacity higher than 36 kV
- The costs for AT/AT are determined by using the average costs of all *Centros de transformación de caseta, Centros de transformación en local, Centros de transformación de intemperie and Centros de transformación subterráneo* with capacity higher than 36 kV
- The costs for AT/MT are determined by using the average costs of all *Centros de transformación de caseta, Centros de transformación en local, Centros de transformación de intemperie and Centros de transformación subterráneo* with capacity lower than 36 kV
- The costs for distribution centers are determined by using the average costs of all Centros de reparto, seccionamiento o reflexión with capacity lower than 12 kV
- There is no detailed data is available on the amount of LV lines. The investment costs of LV lines are calculated using information on the average annual investments (from 2004 to 2016) of LV lines and total average investments and combining this with information on the the total investments.

Assumptions regarding the transmission network

- The costs for 400 kV lines are determined using the average costs of all 400 kV Líneas aéreas with a length greater than or equal to 10 km
- The costs for 220 kV lines are determined using the average costs of all 220 kV Líneas aéreas with a length greater than or equal to 10 km
- The costs for substations of 400 kV are determine by using the average costs of all Posiciones convencionales, Posiciones móviles with capacity of 400 kV
- The costs for substations of 220 kV are determine by using the average costs of all Posiciones convencionales, Posiciones móviles with capacity of 220 kV
- The costs for substations of 400 kV to 220 kV transformers are determined by using the average costs of Transformadores monofásicos and Transformadores trifásico

CHANGES IN (AVERAGE) LOAD ON NETWORK

For the four network levels the average load on the network is calculated in the present situation and for the DSPV case.

In ETM-SA the load on the total electricity network is modelled with a time resolution of one hour. The peak load (maximum load in a year) of every voltage level is shown in the table below.

Table A.5 Peak load on different voltage levels of the electricity network in Andalusia as modelled in ETM-SA.

	Peak load no additional PV [GW]	Peak load DSPV [GW]
Transportation network	5.92	4.59
Distribution network (HV)	5.92	5.49
Distribution network (MV)	5.22	4.85
Distribution network (LV)	4.02	3.79

ADDITIONAL NETWORK INVESTMENTS REQUIRED IN ANDALUSIA IN THE DSPV CASE

Table A.6 Additional network investments required in Andalusia in the DSPV case, base on the FLEXNET study.

	Required extra investment (based on FLEXNET)	Investment costs [euro]	Depreciation costs [euro]	O&M costs [euro/year]
Línea 400 kV	0%	€0	€0	€0
Línea 220 kV	0%	€0	€0	€0
Subestaciones 400 kV	0%	€0	€0	€0
Subestaciones 220 kV	0%	€0	€0	€0
Transformadores 400/220 kV	0%	€0	€0	€0
Lineas AT	1%	€191 mln	€4.8 mln	€2.0 mln
Lineas MT	1%	€41 mln	€1.0 mln	€0.4 mln
Lineas LT	2%	€102 mln	€2.6 mln	€1.1 mln
Subestaciones	6%	€10 mln	€0.3 mln	€0.3 mln
AT/AT	6%	€0.6 mln	€14000	€27000
AT/MT	6%	€2.1 mln	€52000	€47000
Centros de distribucion	5%	€58 mln	€1.5 mln	€1.3 mln

ANNEX 3

DETAILS OF CALCULATIONS OF FINANCIAL EFFECTS OF DSPV

Periods in tariff 3.0A[48]

Table A.7 Periods in tariff 3.0A.

	Winter			Summer		
	P1	P2	P3	P1	P2	P3
Weekdays	18h-22h	8h-18h 22h-24h	0h-8h	11h - 15h	8h-11h 15h-24h	0h-8h

Total cash flows from customer to government and system operator

Table A.8 Total cash flows from customers in tariff 2.0A and 3.0A to government and system operator in Andalusia.

Andalusia	Customer to government No PV	Customer to government DSPV	Customer to system operator No PV	Customer to system operator DSPV current market model, no transitory charge on self-consumed electricity	Customer to system operator DSPV with transitory charge on self-consumed electricity
Bono social (Tariff 2.0A)	€85	€60	€185	€155	€210
PVPC (Tariff 2.0A)	€145	€100	€295	€235	€310
Mercado libre (Tariff 2.0A)	€170	€115	€320	€255	€340
SME (Tariff 3.0A)	€1,120	€720	€1,135	€990	€1,230

48 Obtained from: http://potenciaelectrica.es/tarifa-3-0-a-toda-la-informacion/

Table A.9 Total cash flows from customer to government and system operator in Catalonia.

Catalonia	Customer to government No PV	Customer to government DSPV	Customer to system operator No PV	Customer to system operator DSPV current market model, no transitory charge on self-consumed electricity	Customer to system operator DSPV with transitory charge on self-consumed electricity
Bono social (Tariff 2.0A)	€85	€60	€190	€160	€120
PVPC (Tariff 2.0A)	€125	€90	€265	€220	€280
Mercado libre (Tariff 2.0A)	€145	€100	€290	€235	€405
SME (Tariff 3.0A)	€1,125	€680	€1,290	€1,065	€1,325

Levelising (avoided) costs of DSPV and natural gas

Levelising refers to dividing the total costs (including capital, O&M and fuel costs and interest rates) over the power production (or, if calculating levelised cost of conserved carbon, total avoided CO_2 emissions) from a generation technology over its lifetime.

In this case we do not only levelise the costs of natural gas and DSPV power generation (as provided in section 3.3), but we will also levelise the ***avoided*** costs of natural gas power generation due to deployment of DSPV. To do this, the following components were divided by the additional (compared to the No Additional PV case) DSPV production:

- Total avoided annual fixed O&M costs of natural gas power generation;
- Total avoided annualised investments (as provided in section 3.1) in natural gas power generation. To annualise the avoided investments we applied a technology lifetime of 30 years and an interest rate of 4%.

In general, levelised costs (LC) can thus be calculated by dividing the total costs over the technology lifetime with the total lifetime power production of a technology. This can be simplified by assuming that fuel costs, power generation and O&M costs are constant over the years. Since we want to look at the net value in 2030, this simplification is justified. The simplified formulae to calculate LC is:

$$LC = \frac{\alpha I + FOM + VOM + F}{E}$$

Where:

αI = Annualised investments costs where:

$$\alpha = \frac{r}{(1-(1+r)^{-L})}$$

r = the interest rate

L = the technology lifetime

FOM = total annual fixed operation and maintenance costs

VOM = total annual variable operation and maintenance costs (depending on the actual production).

F = total annual fuel costs.

E = the total electricity produced annually.

If variable operational costs and fuel costs are already expressed per MWh, one could also express the LC as:

$$LC = \frac{\alpha I + FOM}{E} + vom + f$$

where:

vom = the variable operation and maintenance costs per MWh electricity

f = fuel cost per MWh electricity, which is the fuel costs divided by the efficiency of power generated.

To calculate the avoided costs, *I, FOM, VOM* and *F* represent the avoided costs related to natural gas power production (natural gas power production costs in the No Additional PV case minus natural gas power production costs in the DSPV case), α is based on the technology lifetime of a CCGT plant and *E* expresses the additional DSPV production.

Fuel costs in 2030 are based on the IEA World Energy Outlook 2017 New Policies Scenario.[49]

49 IEA (2017). World Energy Outlook 2017. International Energy Agency (IEA), Paris.

ANNEX 4

ENERGY TRANSITION MODEL USEFUL RESOURCES AND LINKS

ETM

- 2030 Spain DSPV: https://pro.energytransitionmodel.com/scenarios/364011
- 2030 Spain No additional PV: https://pro.energytransitionmodel.com/scenarios/364009

ETM-SA

ETM-SA was used for the backbone of the financial calculation. Monetary flows between consumers, government and supplier are modelled in ETM-SA. The amount of self-consumed electricity is also determined in ETM-SA, on an hourly basis. The monetary flows related to self-consumption and remuneration are calculated in an external calculation. For details on this please contact the authors.

Andalusia

- 2015 Andalusia: https://moses.energytransitionmodel.com/testing_grounds/755
- 2030 Andalusia No additional PV:: https://moses.energytransitionmodel.com/testing_grounds/793
- 2030 Andalusia DSPV: https://moses.energytransitionmodel.com/testing_grounds/783
- 2030 Andalusia Bono social no PV:https://moses.energytransitionmodel.com/testing_grounds/785
- 2030 Andalusia Bono social 2 kW PV: https://moses.energytransitionmodel.com/testing_grounds/786
- 2030 Andalusia PVPC no PV: https://moses.energytransitionmodel.com/testing_grounds/787
- 2030 Andalusia PVPC 2 kW PV: https://moses.energytransitionmodel.com/testing_grounds/788
- 2030 Andalusia Mercado libre no PV: https://moses.energytransitionmodel.com/testing_grounds/789
- 2030 Andalusia Mercado libre 2 kW PV: https://moses.energytransitionmodel.com/testing_grounds/790
- 2030 Andalusia SMEs/3.0A: https://moses.energytransitionmodel.com/testing_grounds/840
- 2030 Andalusia SMEs/3.0A 15 kW PV: https://moses.energytransitionmodel.com/testing_grounds/839

Catalonia

- 2030 Catalonia Bono social no PV: https://moses.energytransitionmodel.com/testing_grounds/798/business_cases/562
- 2030 Catalonia Bono social 2 kW PV: https://moses.energytransitionmodel.com/testing_grounds/799/business_cases/563
- 2030 Catalonia PVPC no PV: https://moses.energytransitionmodel.com/testing_grounds/800/business_cases/564
- 2030 Catalonia PVPC 2 kW PV: https://moses.energytransitionmodel.com/testing_grounds/801/business_cases/565
- 2030 Catalonia Mercadoc libre no PV: https://moses.energytransitionmodel.com/

testing_grounds/802/business_cases/566

- 2030 Catalonia Mercado libre 2 kW PV: https://moses.energytransitionmodel.com/testing_grounds/803/business_cases/567
- 2030 Catalonia SMEs/3.0A No additional PV: https://moses.energytransitionmodel.com/testing_grounds/838
- 2030 Catalonia SMEs/3.0A 15 kW PV: https://moses.energytransitionmodel.com/testing_grounds/837

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