Grid Integration Cost of PhotoVoltaic Power Generation

Direct Costs Analysis related to Grid Impacts of Photovoltaics

D. Pudjianto, P. Djapic, J. Dragovic, G. Strbac

Imperial College London, September 2013

Supported by INTELLIGENT ENERGY EUROPE

PVPARITY

TABLE OF CONTENT

Executive Summary

Photovoltaics have emerged as one of the key technologies for generating electricity from renewable sources. Rapid increase in the new installations of PV modules across Europe in the past few years demands better understanding of the system impacts that PV will bring to the European electricity systems. These impact assessments and quantifications are critical for determining the actual full cost of PV and subsequently the competitiveness of PV in relation to other generation technologies.

In this report, an expert team from Imperial College of London, presents the approaches and the results of quantifying PV system integration costs in 11 key EU markets. The aim is to check the feasibility of installing up to 480 GW PV by 2030, covering more than 10% of the European electricity demand. The report shows that not only it is technically feasible but also that the costs of implementing the necessary system integration measures are relatively modest.

One of the major findings is that the back-up capacity cost can be an important component of PV integration costs, especially in Northern Europe (circa €14.5/MWh).This reflects the lower ability of PV to displace conventional generation capacity, compared with Southern Europe where this cost is lower and may be even negative when there is a strong correlation between PV output and peak demands.

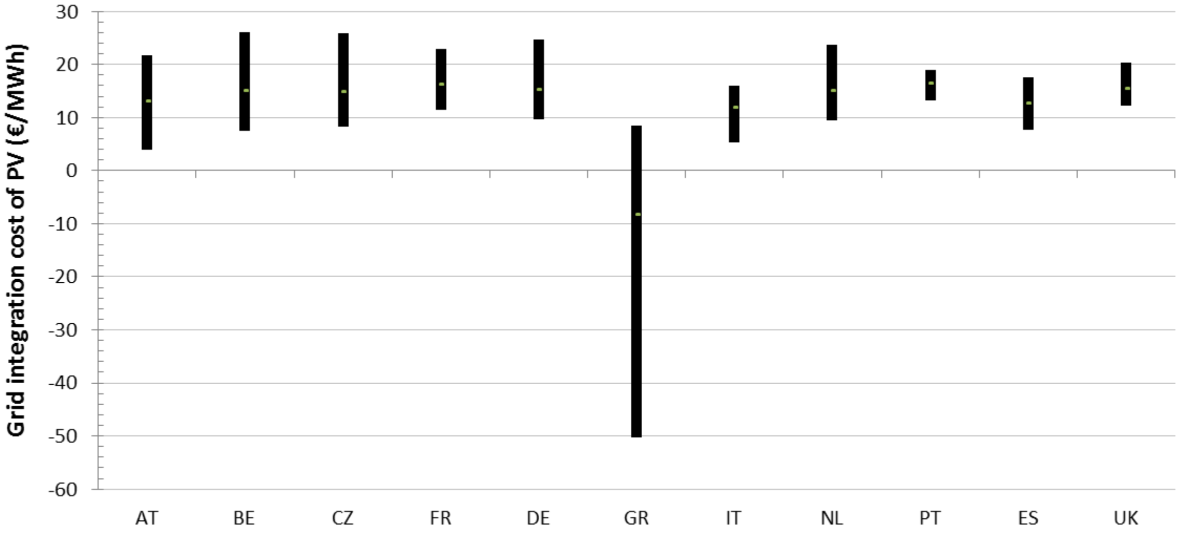
The second major cost component of PV integration is the distribution network cost of PV. Reinforcing distribution networks to accommodate PV would cost about €9/MWh by 2030. This cost usually reduces when peak consumption coincides with peak PV production, as it would be the case in Southern Europe.

Another important result of the analysis is that transmission cost linked to the integration of 480 GW PV by 2030 remains modest. In 2020 the cost is estimated circa €0.5/MW, increasing to €2.8/MWh by 2030.

Balancing costs are another analysed component. Costs reflect the fact that more generators run part-loaded to provide additional balancing services and reserves due to the uncertainty in PV generation production. However this cost will remain modest, circa €1/MWh by 2030, assuming the full integration of EU balancing market.

The impacts of PV on distribution network losses have also been investigated. At low penetration levels, up to 10% energy penetration, PV connected at distribution networks is likely to reduce distribution network losses. Beyond this level, the trend starts to reverse. The threshold varies from country to country. Southern Europe where peak demand coincides with PV output is likely to have a higher threshold. The savings that PV brings in reducing the losses are estimated to be between €2.5/MWh and €5.6/MWh of PV output. This can partially compensate the other grid integration costs. However the savings diminish with the increased penetration of PV.

To summarize, the grid integration cost of PV for the selected target countries for PV penetration levels between 2% and 18% in steps of 2% is illustrated in the next figure. The study concludes that grid integration cost of PV is relatively modest, and it will increase to around €26/MWh by 2030.



The range of grid integration cost of PV in Europe

The report also demonstrates that the applications of Demand Response (DR) or storage solutions can be effective to reduce the integration cost of PV, which could decrease the cost on average by 20%.

1. Introduction to the Project

1.1 THE PV PARITY PROJECT

The PV PARITY project aims at defining grid parity, i.e. achieving a stage of development of the PV technology, at which it is competitive with conventional electricity sources. It will also provide relevant policy makers in the EU Member States with a clear understanding of the necessary measures to support solar PV technology in achieving grid parity. The project will also develop strategies for supporting the PV sector after grid parity is reached. As a result, an increased PV penetration in EU electricity markets and grid will be accomplished at the lowest possible price for the community.

The consortium is made up of knowledgeable partners from the research and academic sector, from the industry and from the energy production sector. The project focuses on 11 EU countries, namely Austria, Belgium, Czech Republic, France, Germany, Greece, Italy, The Netherlands, Portugal, Spain and United Kingdom. The country selection aims to cover a large proportion of the EU electricity market and to be representative of various country configurations in terms of electricity prices, maturity of the national PV market and growth potential in the coming years. Some MENA countries will also be considered, in view of their high PV market potential.

The project starts from the assumption that the goal of existing support schemes is to help the PV technology become competitive with conventional electricity sources in the coming years. However, the support to PV from policy makers is under heavy pressure and some countries are already experiencing signs of a downturn in the level of support from policy makers as well as from the public opinion.

1.1.1 Project strategic objectives

The strategic objective in the long-term of the PV Parity project is to ensure an appropriate policy framework for photovoltaics in order to achieve up to 12% of the EU electricity demand by 2020. This target for 2020 will imply reaching a total installed capacity of about 390 GWp according to the EPIA, SET For 2020 study. In order to achieve this aim, in the first part of the project, the steps necessary to define grid parity will be carried out. This implies to identify the parameters which may influence the grid parity:

- PV generation costs - projections;
- electricity prices, especially in the coming decade – projections;
- the impact of PV generation on base-load, mid-merit and peak-load generation in terms of technical and economic challenges and opportunities;
- the role of technologies that can be used to minimise the cost or maximise the benefits of PV such as storage, and demand response;
- electricity transmission and distribution costs.

In Figure 1 the parameters influencing the PV parity are shown.

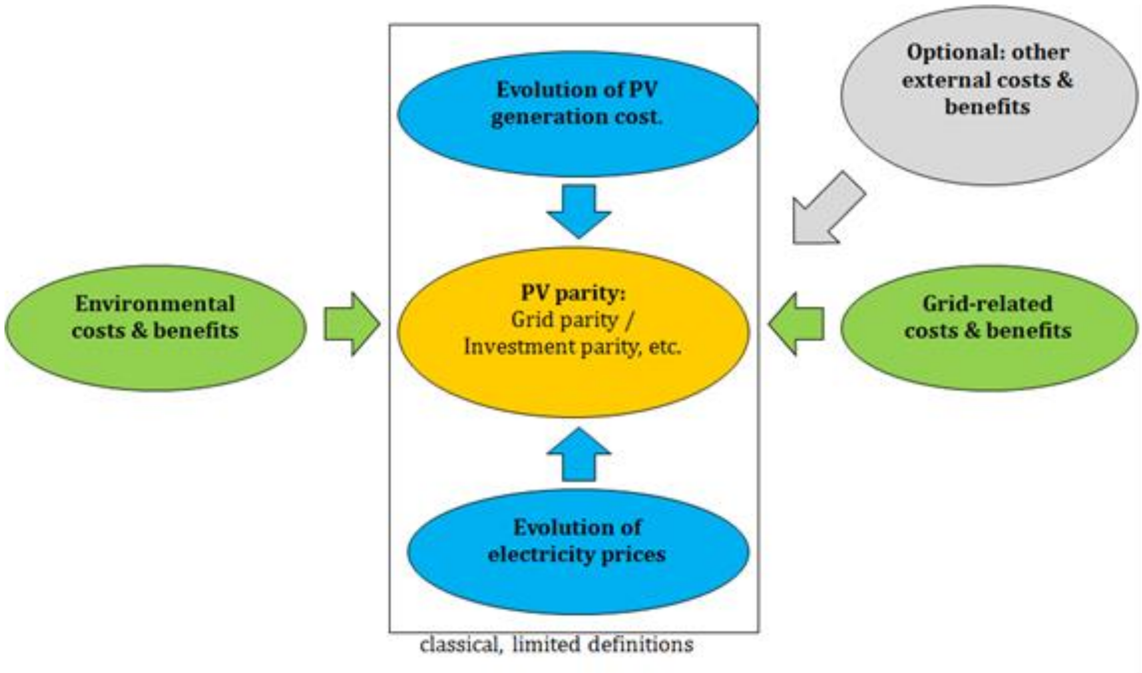


Figure 1: Parameters influencing PV parity: the classical, limited approaches, which only look at PV generation and electricity prices, and the more sophisticated approaches used in the project. Source: ECN, Wim Sinke.

The project will also present information which is needed to identify support schemes most appropriate to reach grid parity and also include information on PV market developments and regulations in several European and MENA countries.

The PV Parity project started in June 2011 and it will end in November 2013. The PV Parity project is co-financed by the European Commission in the framework of the Intelligent Energy Europe (IEE) Program (Contract No. IEE/10/307 / SI2.592205).

1.1.2 Project partners

The list of the partners cooperating in this project is shown below. More information about them and the project is available under www.pvparity.eu.

WIP	www.wip-munich.de
EPIA	www.epia.org
ECN	www.ecn.nl
TUC	www.enveng.tuc.gr
SUER	www.stiftung-umweltenergierecht.de
GSE	www.gse.it
EGP	www.enelgreenpower.com
ICON	www.imperial-consultants.co.uk
TUW	www.tuwien.ac.at
IDAE	www.idae.es
EDF EN	www.edf-energies-nouvelles.com

2. Introduction to this Deliverable

2.1 Context

Photovoltaics (PV) have emerged as one of the key technologies for generating electricity from renewable sources. This has been demonstrated by the rapid increase in the new installations of PV modules in the past few years. While the environmental related benefits of PV in reducing Green House Gas including CO_2 emissions are relatively clear, the impacts of PV on the incumbent power system are less well understood. These system integration impacts need to be assessed in order for the overall cost of PV to be quantified. In the context of PV parity, the competitiveness of PV in relation to other generation technologies should be evaluated based on the full cost of PV that includes system integration costs in addition to manufacturing and installation costs.

It is therefore essential to understand the total cost of PV, which contains the Levelized Cost of Electricity (LCOE) of PV and the system cost of PV. The latter is defined as the total of additional infrastructure and/or additional operating costs to the system as a result of integrating PV power generation.

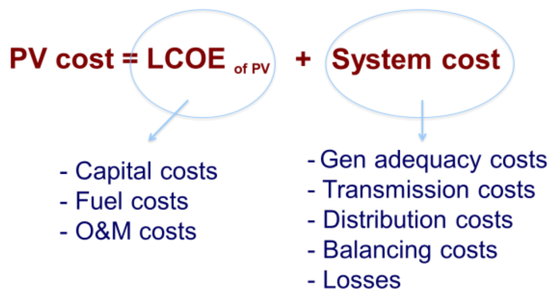


Figure 2 Total cost of PV

LCOE considers the capital cost and O&M cost of PV over the project life while the system cost of PV includes the system capacity costs associated with capacity needed for security, network costs, balancing costs and cost of losses. Both account the total cost of PV. While some information about the LCOE of PV is available[1] the information related to the system integration cost of PV on the European power systems was missing.

> The competitiveness of PV compared to other low carbon or traditional power sources should be evaluated based on the full cost, LCOE and grid integration cost.

2.2 Objective

In this context, the overall aim of the report is to analyse and quantify the grid integration cost and benefit of PV for selected target European countries by evaluating the impacts of increased penetration of PV power generation technology on the future power system infrastructure and operating requirements. The analyses described in this report focus on the impacts of PV on (i) the capacity requirements of generation needed for maintaining reliability of electricity supply, (ii) main European transmission corridors, (iii) distribution systems and (iv) as well as the operating reserve requirements and losses. Insights from these studies are used to inform the work on determining the grid parity of PV.

[1] Branker, K.; Pathak, M.J.M.; Pearce, J.M. (2011). "A Review of Solar Photovoltaic Levelized Cost of Electricity". *Renewable and Sustainable Energy Reviews* **15** (9):4470.

2.3 Scope

The following outlines the scope of PV's grid integration costs that have been quantified in this project.

2.3.1 Capacity credit and additional capacity cost of PV

The capacity credit of PV reflects the firm capacity of incumbent conventional generators that can be displaced by PV. This particularly depends on the availability of PV during peak demand conditions. For Northern European countries where peak demand occurs during winter evening, the capacity credit of PV is relatively low or practically zero. In this condition, PV cannot displace the capacity of conventional generators although it displaces their energy. This increases the cost of incumbent generators as they have to remunerate the same capacity cost with reduced capacity factors.

However for Southern Europe where the maximum PV output may coincide with summer peak demand, the capacity cost may become negative as PV displaces the capacity of incumbent generators more than their energy.

It is important to note that the additional capacity cost of PV is not related to the manufacture/installation cost of PV but to the increase in capacity cost per MWh output of incumbent generation as they need to operate with lower load factors to remunerate their investment costs.

2.3.2 Costs and benefits of PV on the capacity of European main transmission corridors

We also have evaluated the impact of PV on the main European transmission network capacity. The capacity factor of PV in Southern Europe is expected to be twice than the capacity factor of PV in Northern Europe. Therefore it can be expected that in the future, significant capacity of PV may be deployed in Southern Europe or in Middle East North Africa (MENA) countries. This will require reinforcement of European main interconnectors. The additional network capacity required due to increased PV penetration and the associated network cost has been calculated and discussed later in the report.

2.3.3 Operating reserve cost of PV

In this project, the effect of PV intermittency on the increased short term operating reserves for demand-supply balancing has also been analysed. As operating reserves especially the spinning reserves are typically obtained from running generators part loaded, the increase in reserve requirement means that more generating plants will need to run part loaded. This reduces the operational efficiency of the plants and subsequently increases their operating cost and carbon emissions.

2.3.4 Costs and benefits of PV on distribution network capacity and losses

Increased penetration of PV system, on the one hand, at a certain point may trigger distribution network problems such as over-voltages due to voltage rise effects, thermal overloading, and/or reverse power flows. In this case, distribution networks may need to be reinforced and the corresponding cost can be defined as the additional distribution network cost of PV.

On the other hand, PV may bring benefits such as reduction in circuits' peak load and therefore it may release network capacity, supporting voltage for heavily loaded circuits, and lead to reduction in losses. In this case, the cost may become negative indicating the benefits of PV in reducing network costs.

2.3.5 Demand Response as a mitigation measure

In order to minimise the PV integration cost to the system, we have analysed the benefits of Demand Response (DR)/ energy storage applications for load management. By time-shifting the load, DR/storage can increase the self-consumption of the PV output. Generally, this will minimise the impact of PV on the grid and therefore reduces the integration cost of PV.

In this report, we have not implemented an integrated control strategy of DR across different applications. Consequently, there may be conflicts between different applications; therefore the results obtained in the study tend to be optimistic. Nevertheless, it will provide insight on the potential value of implementing DR technologies to support deployment of PV power generation in European electricity system.

2.3.6 Target countries

Our studies focus on a set of target countries, i.e. Austria (AT), Belgium (BE), Czech Republic (CZ), France (FR), Germany (DE), Greece (GR), Italy (IT), Portugal (PT), Spain (ES), the Netherlands (NL), and the United Kingdom (UK).

2.4 Structure of the report

In the next chapter, the methodologies used in quantifying the system integration cost of PV and the key results for each cost categories are summarised and discussed. In Chapter 4, the key results and analysis of the impacts of PV in all selected target countries are described. In the end, we provide the conclusions of the overall findings presented in the report.

3. Overview of the Approaches and the Key Results

3.1 Quantifying additional capacity cost of PV

In order to calculate the magnitude of the additional capacity costs driven by PV technology, we use the following expression[2]:

Percentage displaced capacity of incumbent generation due to penetration of PV

$$\Delta C_{PV} = \left(1 - \frac{D^C}{D^E}\right).C^{I_0}$$

Additional capacity cost of PV

Percentage displaced energy of incumbent generation due to penetration of PV

Per-unit capacity cost of incumbent technology

Figure 3 Additional capacity cost of PV

As the above expression shows, the ratio between conventional generation capacity that can be displaced by PV (expressed as percentage, D^C) and the energy production of conventional generation that can be displaced by PV (expressed as percentage, D^E) is one of the main factors that determine the additional capacity cost attributable to PV. The other factor is the capacity cost of the conventional generation. We assume that the marginal conventional generation affected by PV is gas fired generation technologies. We assume that the annuitized capital cost of gas fired generation is circa €67/kW per year.

We note that the ratio between the capacity of gas plant that can be displaced by PV, and the installed capacity of PV, while maintaining the same level of security of supply is defined as the capacity credit of PV.

The displaced energy production of conventional generation is equal to the ratio of expected output production from PV and the expected output production of the conventional plant (with no PV). Since PV is a zero marginal cost plant; therefore it has a priority dispatch.

Equation (1) shows the ratio of between the load factor of PV and the load factor of gas fired power generation technologies.

$$D^E = LF_{PV}/LF_{gas} \qquad (1)$$

where LF_{PV} is the load factor of PV and LF_{gas} is the load factor of gas fired power generation in a system without PV.

To quantify the capacity of conventional generation that can be displaced by PV and the PV installed capacity, we apply the established generation adequacy assessment model which in principle follows the model used to evaluate the capacity credit of wind[3]. The model calculates system reliability indices given a predefined generation and demand background.

[2] Goran Strbac, Anser A Shakoor, "Framework for Determining System Capacity Cost of Intermittency PART 1: Two technology system", Technical Report for DTI Centre for Distributed Generation and Sustainable Electrical Energy, UK, March 2006

[3] Anser A Shakoor, Goran Strbac, Ronald N. Allan, "Quantifying Risk of Interruptions and Evaluating Generation System Adequacy with Wind Generation", the 9th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS) June 2006, Sweden

Table 1 Additional generating capacity cost of intermittent power technology (€/MWh)

Load factor	Capacity credit										
	0%	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%
5%	14.07	6.42	-1.23	-8.88	-16.52	-24.17	-31.82	-39.47	-47.12	-54.77	-62.41
10%	14.07	10.25	6.42	2.60	-1.23	-5.05	-8.88	-12.70	-16.52	-20.35	-24.17
15%	14.07	11.52	8.97	6.42	3.87	1.32	-1.23	-3.78	-6.33	-8.88	-11.42
20%	14.07	12.16	10.25	8.33	6.42	4.51	2.60	0.69	-1.23	-3.14	-5.05
25%	14.07	12.54	11.01	9.48	7.95	6.42	4.89	3.36	1.83	0.30	-1.23
30%	14.07	12.80	11.52	10.25	8.97	7.70	6.42	5.15	3.87	2.60	1.32
35%	14.07	12.98	11.88	10.79	9.70	8.61	7.51	6.42	5.33	4.24	3.14
40%	14.07	13.11	12.16	11.20	10.25	9.29	8.33	7.38	6.42	5.47	4.51
45%	14.07	13.22	12.37	11.52	10.67	9.82	8.97	8.12	7.27	6.42	5.57
50%	14.07	13.31	12.54	11.78	11.01	10.25	9.48	8.72	7.95	7.19	6.42

A reliability criterion, i.e. Loss of Load Expectation (LOLE)[4] must not exceed 4 hours/year, is used in our study. This desired level of reliability is calculated by balancing the costs of additional capacity against the expected cost of interruption in the electricity TSO B.V,2011)[5]. For simplicity, this standard is applied uniformly to all selected target countries.

The model can incorporate all types of generation technologies such as hydro power, wind, PV, nuclear, gas fired plants. All technologies are modelled in sufficient detail according to their individual technical characteristics.

The approach can be summarized as follows. Firstly, we determine the minimum capacity of gas fired plant in a system without PV in order to meet the reliability criterion. Secondly, PV is added to the system and the capacity of gas fired plant is reduced so that the desired level of reliability is maintained. We can therefore calculate the capacity of gas fired plant that can be displaced by PV.

For different load factors and capacity credits of non-conventional generation technologies, we have computed the additional generating capacity costs. As an example, the results are summarised in Table 1. The cost is expressed in €/MWh of the respective generation output.

The results show that for a generation technology that has 0% capacity credit, the additional capacity cost is at maximum (€14.07/MWh[6]) irrespective of the amount of energy it can produce annually. For a generation technology that can displace more capacity than the energy of incumbent generators, i.e. the respective capacity credit is greater than the load factor; the cost is negative as shown in the shaded area of Table 1. The larger the difference between the capacity credit and the load factor, the lower the additional capacity cost of that technology and vice versa.

4 LOLE indicates the expected number of hours in a year in which demand exceeds the available generating capacity in the system, which leads into load curtailment.

5 TenneT TSO B.V.,"Security of Supply Monitoring Report 2010-2026", May 2011

6 This depends on the capex of primary technology and its capacity factor. In this study, we assume that the load factor of marginal gas plant is 54%.

In the context of PV, this demonstrates that the availability of the capacity of PV during peak demand condition is the main factor in determining its additional capacity cost. Another factor is the load factor of PV; the additional capacity cost increases as the load factor increases.

3.1.1 Additional capacity cost of PV

Figure 4 and Figure 5 illustrate the additional capacity cost of PV for the selected target countries in Europe for a range of PV penetration levels between 2% and 18% without and with DR respectively. In these figures, the minimum cost is obtained when the penetration level is low and the maximum cost is obtained when the penetration level is high. In some cases, the range is very narrow, e.g. in Spain (ES) or the UK which indicates that the cost is not sensitive to the PV penetration level. This is generally observed for countries that have winter evening peak load conditions. In the case of Spain and Portugal, our data suggest that peak demand in winter is comparable or higher than the peak demand in summer. The cost can be negative as in the case of Greece due to a strong correlation between PV output and peak demand conditions which occur during summer period.

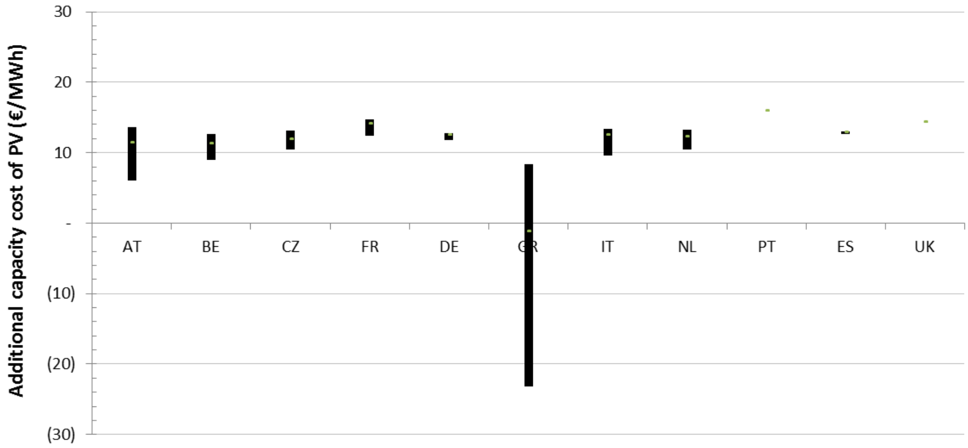


Figure 4 The range of additional capacity cost of PV in Europe for various PV penetration levels (2% - 18%)

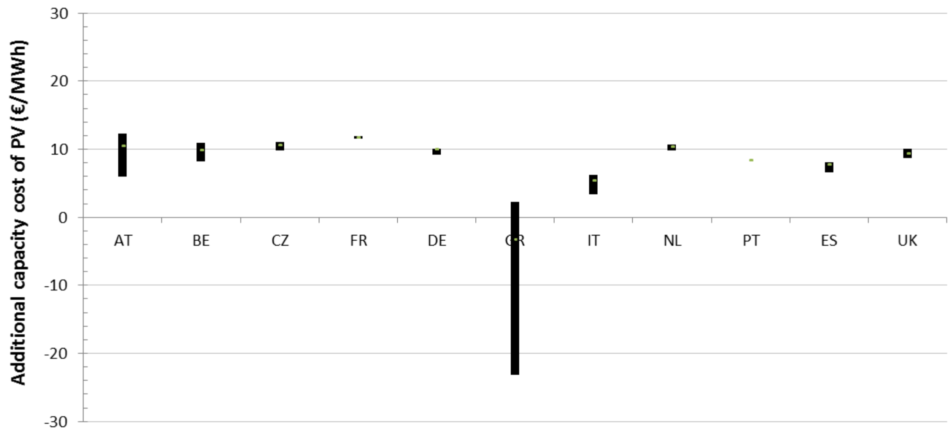


Figure 5 The range of additional capacity cost of PV in Europe with demand response for various PV penetration levels (2% - 18%)

As demonstrated in Figure 5, DR can reduce the grid integration cost. The savings obtained from DR are system specifics and therefore vary from country to country.

3.2 Quantifying the EU Grid cost and the balancing cost of PV

In order to evaluate the impact of PV technology on the capacity of main European grid and the increased operating cost due to increased operating reserves to deal with the intermittency of PV, we have employed the Imperial College's Dynamic System Investment Model (DSIM)[7] to calculate the system operating cost and the incremental network capacity needed to facilitate increase in the installed capacity of PV across Europe.

The model optimizes generation and transmission investment decisions as well as the short-term operation of the entire European system on an hourly basis, including plant dispatch and scheduling of reserve and frequency regulation services to ensure sub-hour (seconds to minutes) balancing of the system. The model takes account of system adequacy and security requirements.

DSIM provides information on the amount of transmission capacity needed in the system to maximize the overall benefits. This enables quantification on the increased network capacity caused by incremental changes in PV installed capacity.

On the other hand, DSIM also estimates the system operating cost, mainly driven by generation costs (fuel, no-load, and start-up cost). This operating cost includes the carbon prices and also the effect of running a generator part-loaded to provide operating reserves. As PV installed capacity increases, the operating reserves also increase to hedge the risk of uncertainty caused by unit unavailability or changes in PV energy sources, amongst others. By comparing the operating costs of two different scenarios, with and without increase in operating reserves, we can derive the changes in system balancing cost due to increased PV capacity.

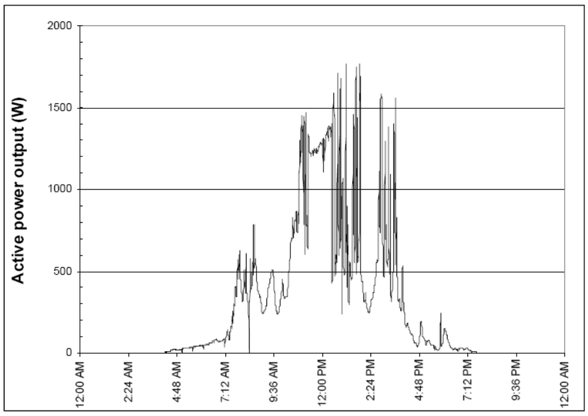


Figure 6 PV power output from a 2.2 kWp PV panel in London

Figure 6 is an illustrative example on how the PV power output varies across time. The aggregated power output variation from a large number of PV installations dispersed geographically will be much lower. Nevertheless it indicates that increased PV penetration will require additional balancing services and increased capacity of operating reserve.

3.2.1 Description of studies

As the impacts of PV on European transmission depend on the reference case selected, two key target years are used as reference cases, i.e. 2020 (240

[7] D. Pudjianto, M. Castro, G. Strbac, and E. Gaxiola, "Transmission Infrastructure Investment Requirements in the Future European Low-Carbon Electricity System", Proc. 10th International Conference on European Energy Market Conference, Stockholm, 27-31 May 2013.

GW) and 2030 (485 GW) based on the EPIA scenarios. Installed capacity of PV is increased incrementally (5%-15%) and the changes on transmission investment proposed by DSIM are used to evaluate the network cost associated with increased PV. Some additional studies have also been carried out, by increasing the PV capacity in a specific target country by 50%. For the 2030 sensitivity study, only one case study has been carried out with 5% increase in PV capacity uniformly across Europe compared to the PV capacity in the 2030 reference case. It is assumed that the capacity of EU Grid has been reinforced according to the ENTSO-E Ten Year Network Development Plan (TYNDP) 2020[8].

In addition to uniform distribution of incremental changes in PV capacity, we have also evaluated the impact of incremental changes in selected target countries such as Italy, France, Germany, Spain, and the UK.

In order to evaluate the impacts of PV on the balancing requirements, two cases are simulated; (i) assuming that the incremental changes in PV does not affect the operating reserve , and (ii) the increased in PV increases the operating reserve.

3.2.2 Additional EU Grid cost of PV

Figure 7 (a) shows the capacity of European main transmission system proposed by ENTSO-E and Figure 7 (b) shows the network capacity required proposed by DSIM to accommodate 240 GW of PV in Europe by 2020. It can be observed visually that some of the corridors particularly the Spain – France interconnectors need reinforcing beyond the proposed capacity by ENTSO-E to accommodate the projected PV 2020 scenario.

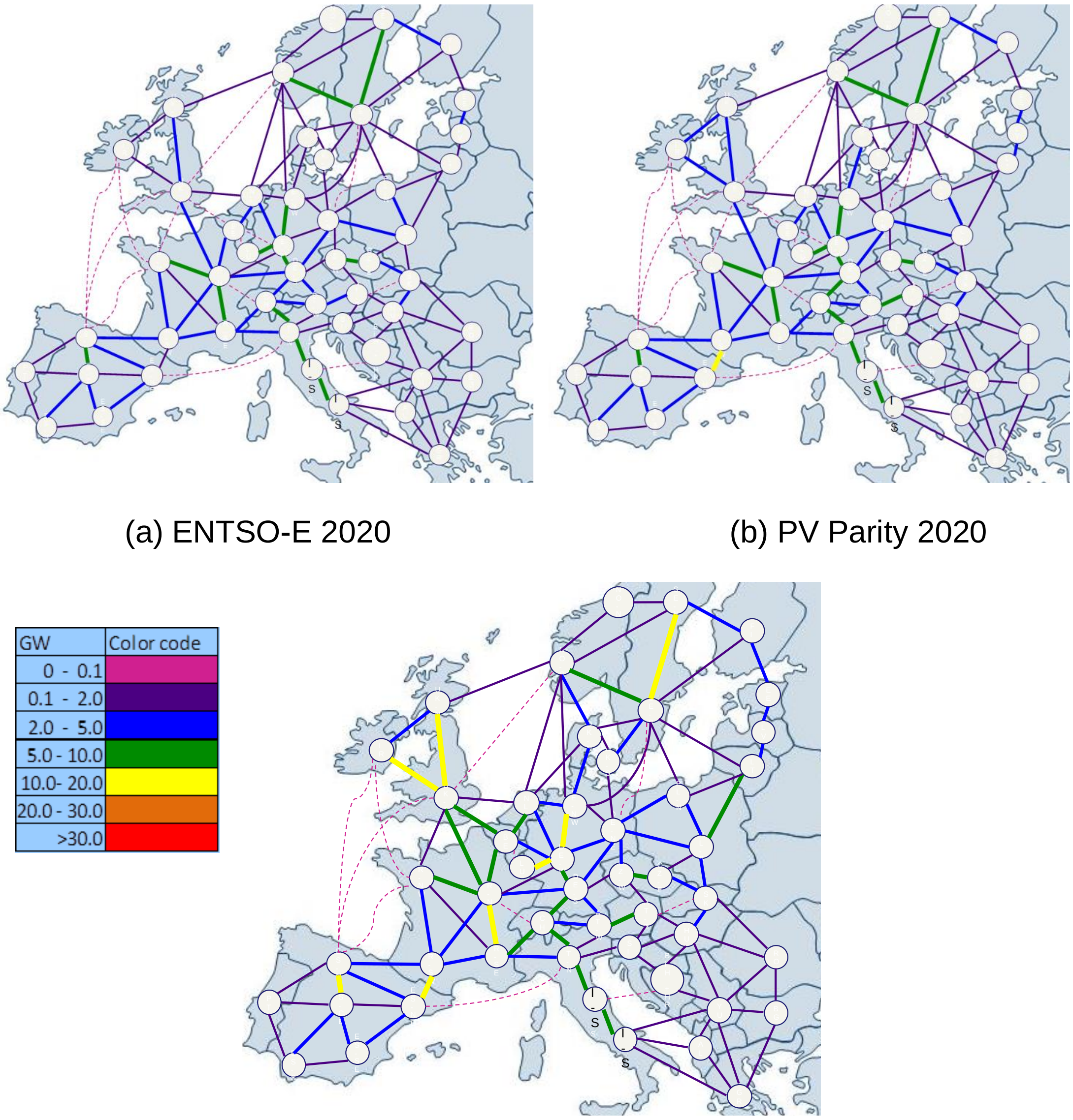
More network investment proposition can be seen in Figure 7 (c) that shows the optimal capacity to accommodate the 485 GW PV Parity of 2030 scenario. It is important to note that not all network investments shown here are driven by PV. Some are driven by other technologies particularly wind power in Northern part of Europe and increase in load.

The results of our analyses are summarised in Table 2, showing that the additional EU grid cost of PV by 2020 is modest, less than €0.5/MWh. Even with increasing further the installed capacity at a particular country up to 50%, the additional cost of PV is still relatively modest. This is likely to be caused by the availability of sufficient capacity margin provided by the 2020 capacity proposed by ENTSO-E.

Table 2 Additional EU Grid cost of PV

Increase in PV installed capacity from the ref. case	Δ grid cost (M€/year)	Δ annual energy output (TWh)	Additional Grid (€/MWh) EU cost
2020			
EU : 5%	4.38	12.9	0.3409
EU : 10%	9.73	25.7	0.3782
EU : 15%	15.42	38.6	0.3997
Spain:50%	0.92	17.6	0.0523
Italy:50%	2.80	25.0	0.1120
France:50%	1.16	25.3	0.0459
Germany:50%	8.55	27.6	0.3103
2030			
EU: 5%	70.	25	2.80

[8] https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2012/



(a) ENTSO-E 2020

(b) PV Parity 2020

(c) PV Parity 2030

Figure 7 Impact of PV on European Transmission Grid

By 2030, higher deployment of renewable power generation including wind power and PV has increased demand for new investment in European grid. It is illustrated in Figure 7 (c) that the capacity of many interconnectors, both cross-border or within the Member States, need to be upgraded. In this condition, the transmission cost of increasing PV capacity increases to €2.8/MW.

It is important to note that in the model, the utilisation of network capacity has been efficiently shared across different generation technologies including renewables.

With regards to wind power, the characteristics of wind energy output are complementary to the characteristics of solar power. Wind is strong in winter periods and evening time while solar is strong in summer period and day time. The weekly output from solar-wind power is shown in Figure 8. Considering the sources of wind are in the North and for solar in the South; this allows power flows to change direction utilising the same network capacity while optimising the use of different renewable sources. This effect is important to drive down the transmission cost of PV.

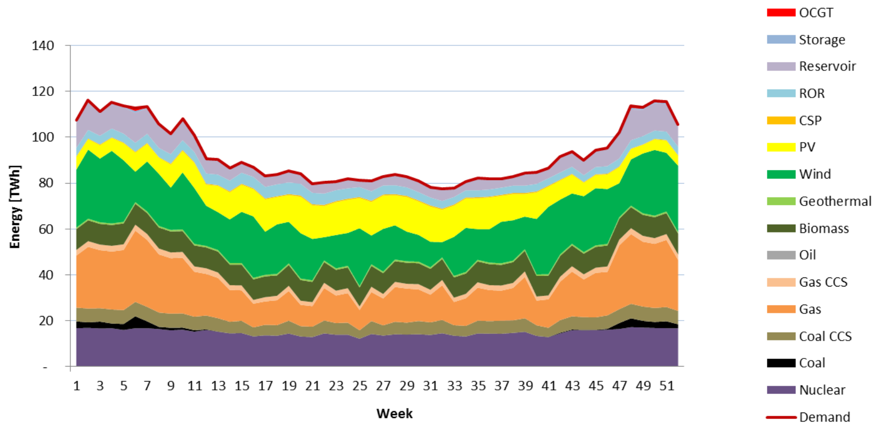


Figure 8 Weekly electricity output from different generation technologies

It is worth to mention that high penetration of PV may also trigger reinforcement for local transmission which is excluded in our analysis. The impact of PV on transmission is also affected by many other factors that cannot be evaluated in isolation. For example, changes in load and generation mixes and generation operating cost, RES profiles and etc.

3.2.3 Balancing cost of PV

Figure 9 and Figure 10 illustrate the additional frequency response and operating reserves (spinning and standing) for the PV parity 2020 scenario for each country. This increase in reserves is needed to deal with the error in forecasting the output of PV.

The increase in frequency response reserve requirements typically will be lower compared to the increase in operating reserves. The timescale for frequency response services is typically below 15 minutes while the operating reserve are needed to deal with much longer (up to 4 hours) credible system changes. With longer time frame, the uncertainty increases.

The increase in reserve has to be provided typically by part loading conventional generators. This decrease operating efficiency and as a result, increase the operating cost. However, some generators can provide this service quite efficiently e.g. hydro plant.

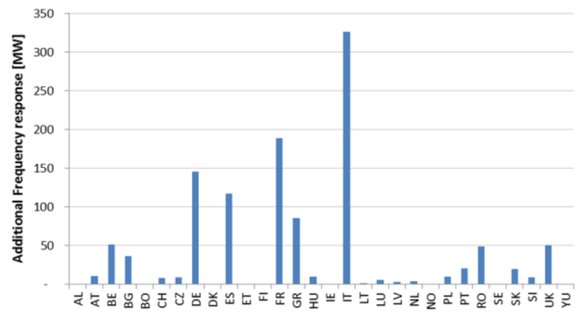


Figure 9 Additional frequency response reserves due to PV intermittency by 2020

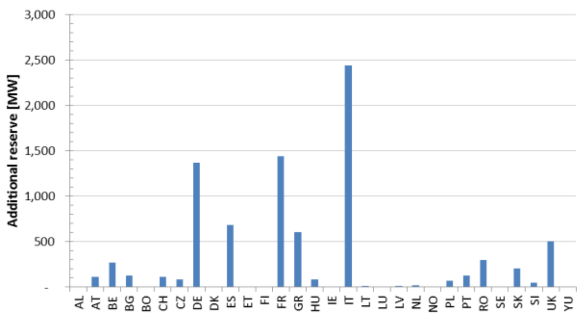


Figure 10 Additional operating reserves due to PV intermittency by 2020

Our studies indicate that the balancing cost due to PV in 2020 is relatively modest, circa €0.5/MWh assuming the full integration of EU balancing market. This increases to €1.04/MWh by 2030. It can be expected that the balancing cost will increase along with the increased penetration of PV.

3.3 Quantifying the additional distribution network cost of PV

In order to calculate the impact of PV on distribution networks, we applied Imperial's distribution network planning tools to create a set of representative distribution network models[9] that resemble LV and HV distribution system in Europe. As the impacts of PV depend, among others, on the topology and characteristics of the distribution networks, it is important to model distribution networks with different characteristics, e.g. urban, semi-urban, semi-rural, and rural networks. In this study, fifteen network models have been created. It model has different characteristics in terms of capacity and voltage level configurations; different mixture of overhead and underground lines, and different load density, number and mixture of customers. Figure 11 illustrates the four voltage (left) and three voltage (right) configurations of generic distribution network models used in this study.

The parameters of the Low Voltage generic network models in terms of length, capacity, etc. have been validated using the Statistical Network Design Tool[10]. Figure 12 illustrates 2 distribution network models that resemble urban and rural models created by the tool. The tool has been validated using actual network data[11].

For this study, we use the generic models to identify the minimum required distribution network reinforcements to accommodate a certain level of PV penetration. The distribution network cost of PV can be calculated by dividing the cost of network upgrade by the annual PV output. The cost is expressed in €/MWh of PV output.

Depending on the penetration level of PV, amongst other factors, the impacts of PV deployment can be positive (benefits) or negative (costs) to the system. For example, PV may release some capacity of the network allowing load growth without necessarily incurring network investment and reduce losses. On the other hand, PV may increase network cost by causing network overloads or due to voltage rise effect. PV generation may also increase losses.

Year round power flow analysis is carried out to calculate losses and to capture critical operating snapshots that drive network capacity; for example, maximum demand with minimum (zero) PV and minimum demand with maximum PV for countries where the peak demand conditions occur during winter evening.

[9] Cao D.M., Pudjianto D., Strbac G., Ferris B., Foster I., Aten M.,"Examination of the impact of possible distribution network design on network losses", CIRED - 20th Intl. Conf. on Electricity Distribution, Prague 8-11 June 2009

[10] Gan C.K., Silva N., Pudjianto D., Strbac G., Ferris B., Foster I., Aten M.," Evaluation of alternative distribution network design strategies", CIRED - 20th Intl. Conf. on Electricity Distribution, Prague 8-11 June 2009

[11] C. K. Gan, P. Mancarella, D. Pudjianto, and G. Strbac, "Statistical appraisal of economic design strategies of LV distribution networks," Electric Power Systems Research, vol. 81, July 2011,pp. 1363-1372.

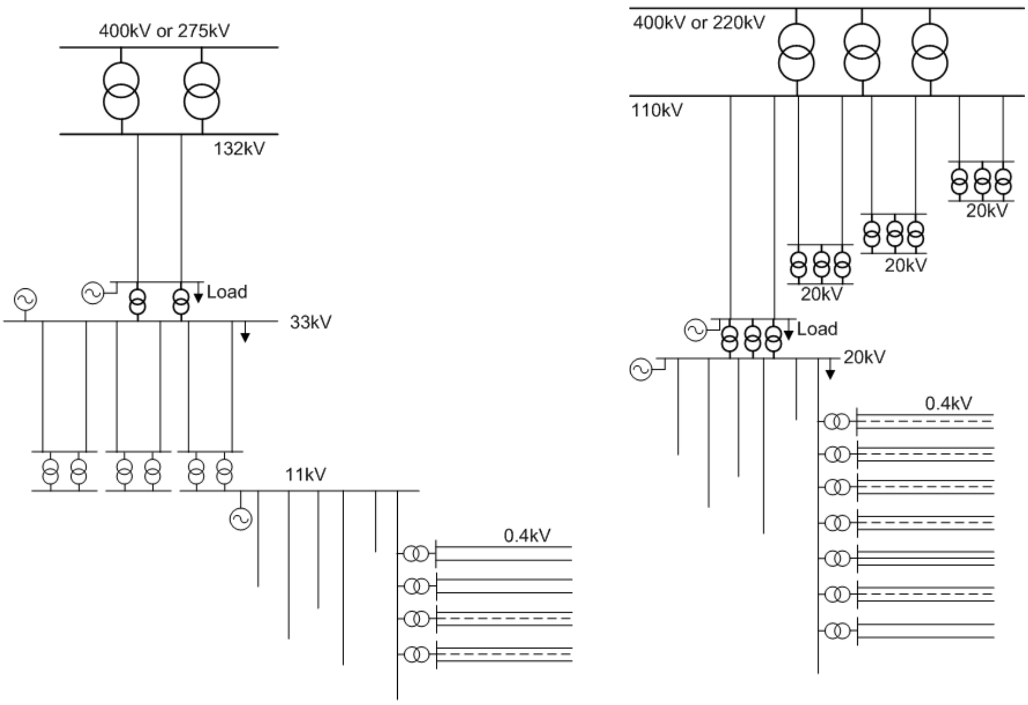


Figure 11 Illustrative diagram of four and three voltage level generic distribution network

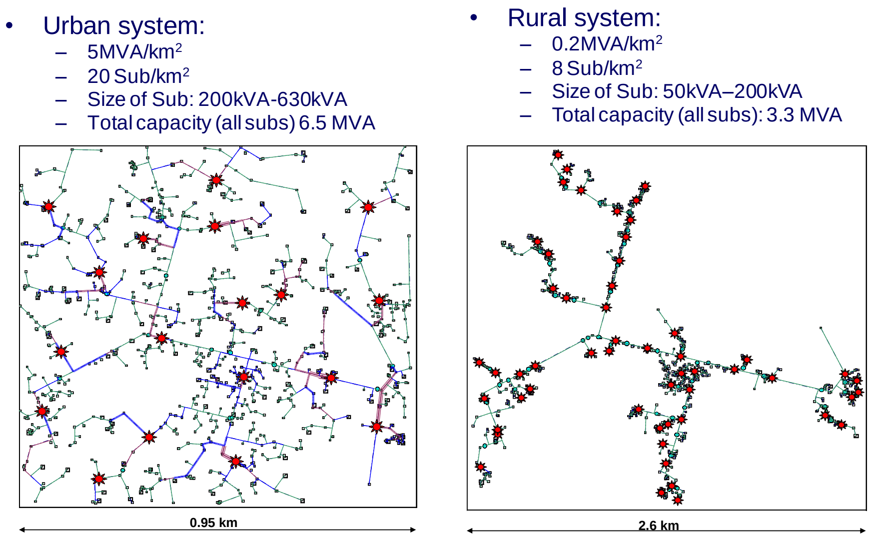


Figure 12 Illustrative example of reference network for urban (left diagram) and rural (right diagram)

3.3.1 Distribution network cost of PV

Figure 13 and Figure 14 show the range of additional distribution network cost triggered by PV installations in the European distribution systems for various penetration levels (2%-18%) without and with DR respectively. The cost is expressed in €/MWh. It is important to note that in this case, the minimum cost is not always obtained when the penetration level is low since the cost tends to decrease at certain extent when PV capacity increases. But up to certain point, varies between 8%-14% penetration level, the cost starts to increase again along with increased PV capacity. The maximum cost is still obtained at the highest penetration level.

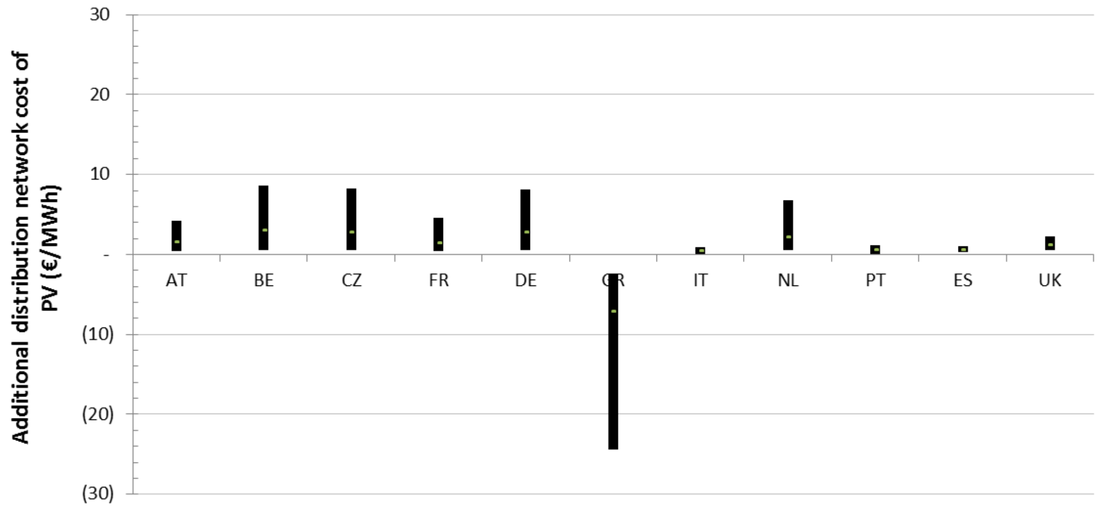


Figure 13 The range of additional distribution network cost of PV in Europe for various PV penetration levels (2% - 18%)

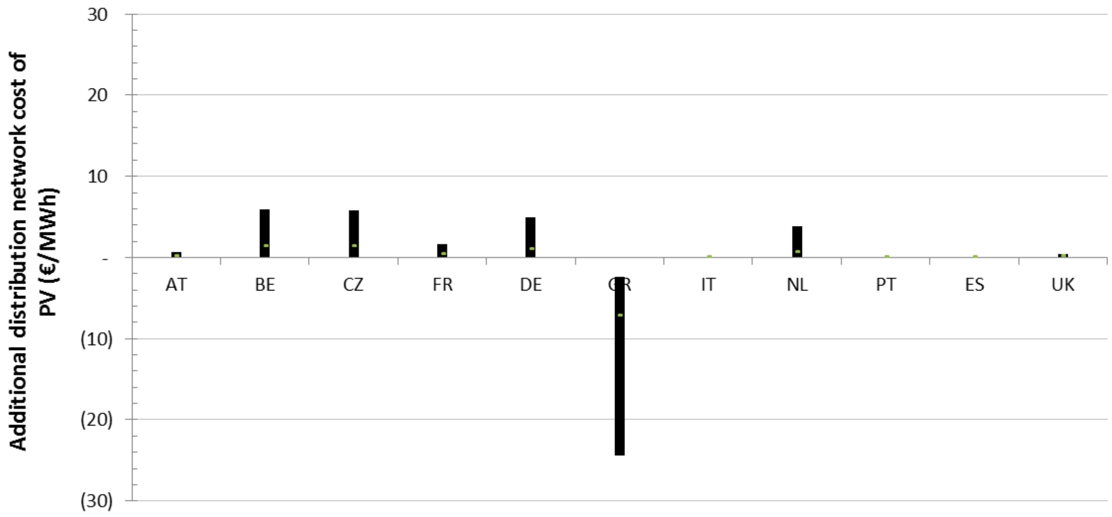


Figure 14 The range of additional distribution network cost of PV in Europe with demand response for various PV penetration levels (2% - 18%)

The cost at low penetration level is very modest. In Greece, the cost is even negative indicating the benefit that PV can bring in reducing/releasing the distribution network capacity in the country. This is due to the strong correlation between peak demand and output of PV. The results also show that the costs in Southern European countries are generally lower than the cost in Northern countries.

At 18% penetration level the cost is still relatively low (circa €9/MWh in Belgium). With DR, the cost can be substantially reduced or completely mitigated as shown in Figure 14.

3.3.2 Impacts on distribution network losses

PV generation may reduce distribution flows in distribution network and reduce network losses. Our studies indicate that the loss reduction that can be obtained is between 0.25% and 0.75% depending on the characteristics of the distribution networks and the penetration level of PV. The impact of PV on losses for rural networks tends to be higher compared to the loss reduction in urban networks due to the length and circuit characteristics of both networks.

Increasing PV penetration up to a certain level will reduce the losses; however there is a point where further increase in PV capacity will start increasing the losses due to increased reverse power flows in the system. This point is reached when PV penetration level is around 8% - 10%. Figure 15 shows the impact on losses of increased PV deployment in distribution networks in Germany, Spain, France, Italy, and the UK with and without DR.

The results of our analysis on all European countries are illustrated in Figure 16. Similar patterns can be observed. It can be concluded that at the current installed capacity of PV until 2020, where the penetration level is still far below 10%, PV contributes to losses reduction in distribution networks.

With the assumption that the cost of losses is €50/MWh, the savings that PV can bring at 2% penetration level are between €2.5/MWh and €5.5/MWh. The savings reduce as the PV penetration level increases. At 18% penetration level, the losses may have increased. This is illustrated in Figure 17.

With DR, the savings in losses improve as DR enhances the self-consumption that leads to loss reduction. At 2% penetration level, the savings vary between €2.5/MWh and €7.5/MWh with Italy has experienced the largest improvement. This is depicted in Figure 18.

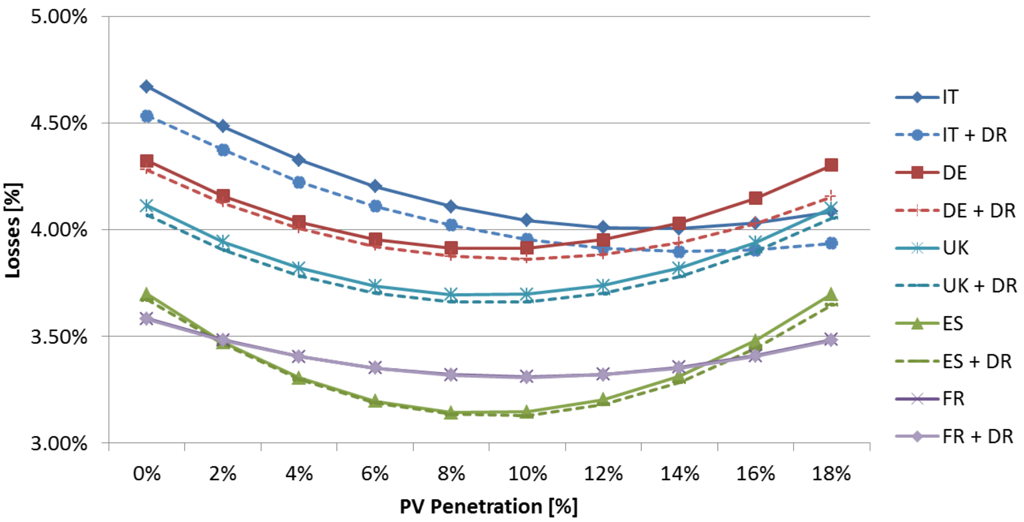


Figure 15 Impact of increased PV penetration on distribution network losses in Germany, Spain, France, Italy and the UK

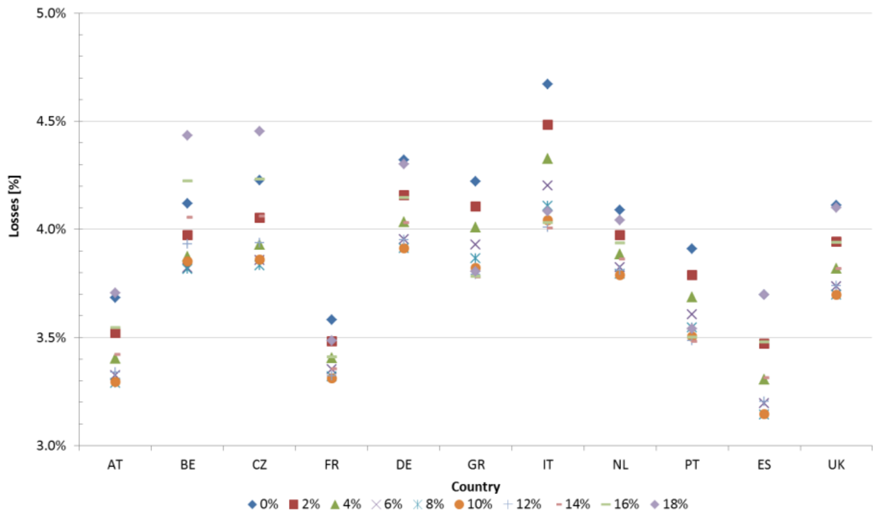


Figure 16 Impact of increased PV penetration on European distribution network losses

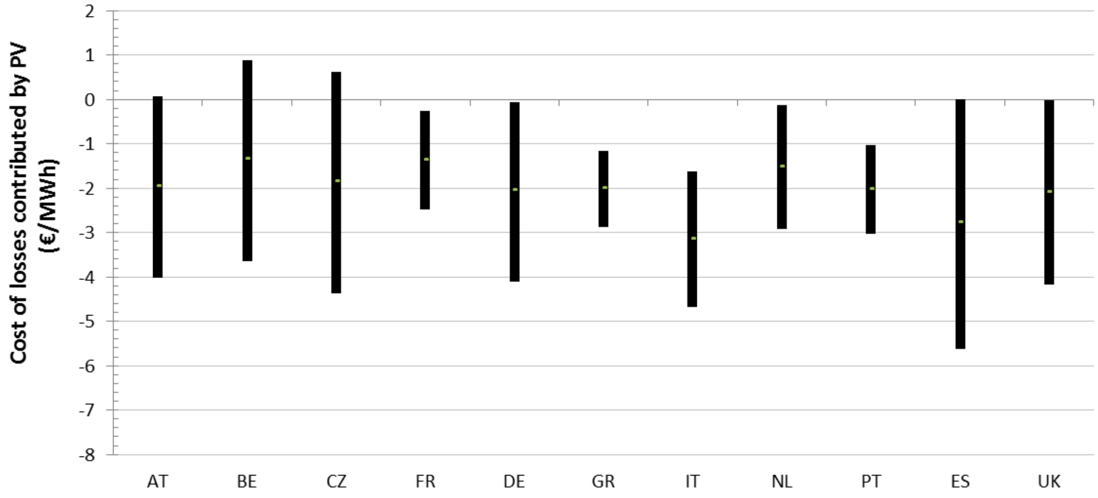


Figure 17 The range of cost of losses contributed by PV in Europe for various PV penetration levels (2% - 18%)

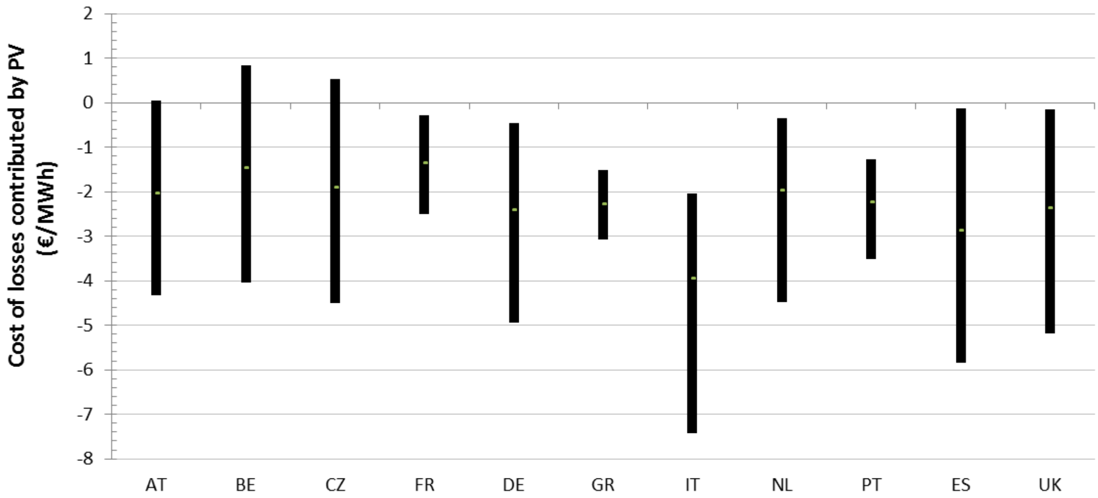


Figure 18 The range of cost of losses contributed by PV in Europe for various PV penetration levels (2% - 18%) with demand response

3.4 Summary

By summing all components of grid integration cost of PV that have been described earlier, the total cost can be derived. This total cost includes the cost of maintaining the adequacy of generation capacity for security purposes, the cost of upgrading EU grid main transmission system, the cost of reinforcing distribution network, the cost of losses attributed to PV and the cost of having more operating reserve requirements due to increased PV generation. The grid integration cost of PV for the selected target countries without DR and with DR are shown in Figure 19 and Figure 20 respectively.

The grid integration cost varies from country to country. At 2% penetration of PV, the cost varies between - € 50/MWh (in Greece) and €13/MWh. At 18% penetration, the cost increases up to €26/MWh. It can be observed that in general the cost in Southern Europe is lower than the cost in Northern Europe.

With DR, the cost at low penetration level varies between -€50/MWh and €9.5/MWh. The cost also reduces by 20% at high penetration level from €26/MWh to €21.5 as illustrated in Figure 20.

More detailed discussions on individual countries are given in the next chapter of this report.

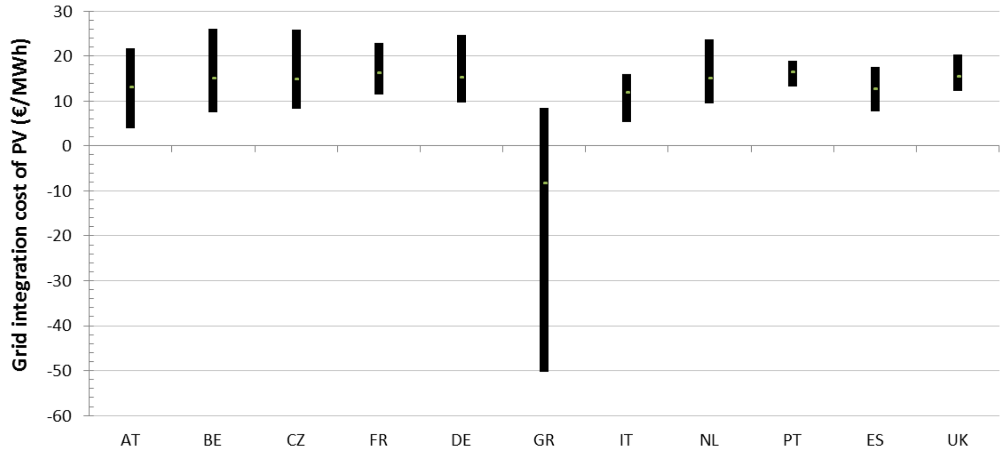


Figure 19 The range of grid integration cost of PV in Europe for various PV penetration levels (2% - 18%)

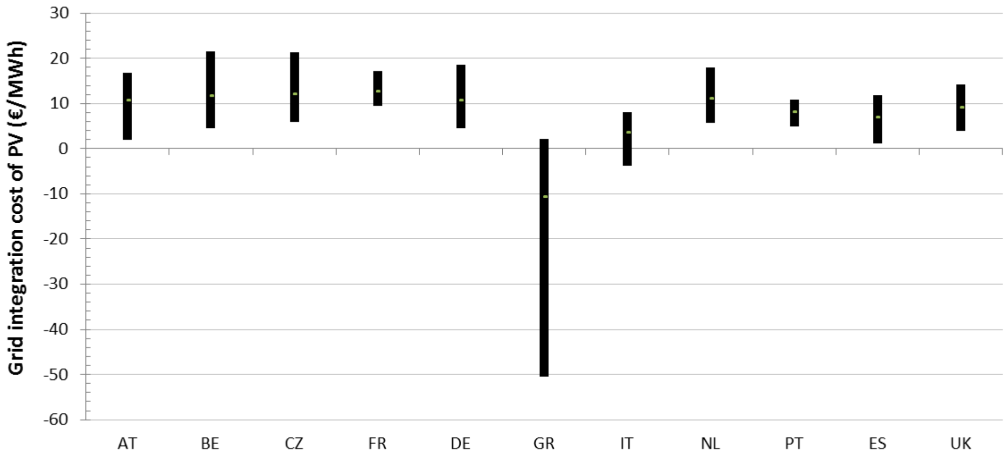


Figure 20 The range of grid integration cost of PV in Europe for various PV penetration levels (2% - 18%)

4.1 Description of case studies

For each selected target country[12], the additional generating capacity cost and the distribution network cost of PV are quantified from 2% up to 18% PV penetration levels in steps of 2%. This percentage reflects the amount of PV energy that supplies the national demand. This range captures the level of PV penetration in Europe projected by EPIA, i.e. 15% by 2030.

The respective installed capacity of PV for each penetration level is derived by taking into account the appropriate PV's capacity factor, which varies across Europe. PV in Southern Europe has larger capacity factors than PV in Northern Europe.

In presenting the penetration level of PV, we use an average national figure. However, it is likely that PV is not uniformly distributed and the level may actually be higher or lower at some areas. Therefore, in interpreting the results especially for the distribution network cost of PV, this factor should be kept in mind.

In order to minimize the negative impacts of PV on distribution networks and to improve the capacity credit of PV, we have investigated the applications of Demand Response (DR). It is assumed that there will be adequate amount of flexible loads that can be used to minimise the peak of the net load profiles (loads – PV output); this strategy generally improves the self-consumption of PV power production.

For each target country, the results are presented by five graphs. The first graph, as illustrated in Figure 21, shows the capacity credit of PV without DR (Cap Credit), the capacity credit of PV with DR (Cap credit [DR]), and the additional capacity cost without (AddCapCost) and with DR (AddCapCost [DR]). The x-axis shows the penetration level of PV with the respective installed capacity of PV in a square-bracket. There are two y-axes; one refers to the capacity credit of PV in percentage of PV's capacity and the second one refers to the additional capacity cost of PV in €/MWh output of PV.

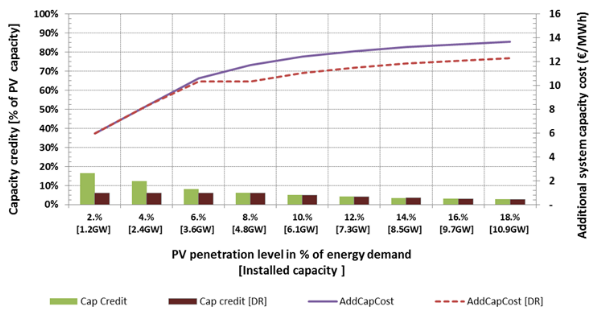


Figure 21 An illustrative graph showing the capacity credit and additional capacity cost of PV with and without DR.

The second graph, Figure 22, shows the magnitude of daily peak demand with the corresponding PV output across one year period taking into account temporal demand variation including generally lower peak during weekend periods.

[12] Austria, Belgium, Czech Republic, France, Germany, Italy, Portugal, Spain, the Netherlands, and the United Kingdom (UK)

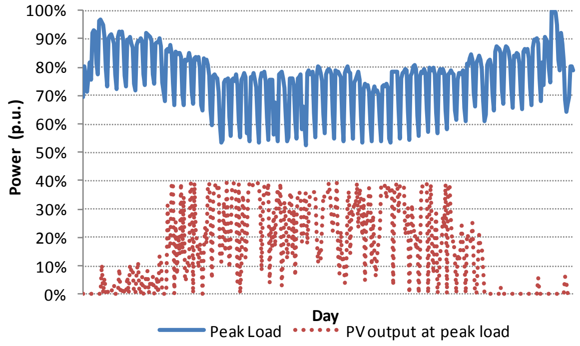


Figure 22 An illustrative graph showing the level of PV output at daily peak demand across one year period

The third graph (Figure 23) illustrates the additional distribution network cost of PV across various PV penetration levels (x-axis) without DR (DisCost) and with DR (DisCost[DR]). The cost is also expressed in €/MWh output of PV.

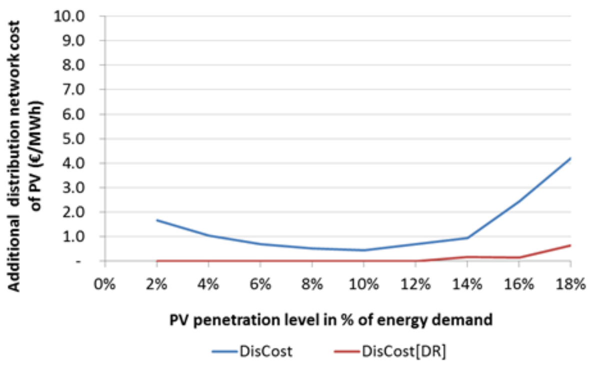


Figure 23 An illustrative graph showing the additional distribution network cost of PV (€/MWh)

The fourth graph (Figure 24) shows the cost of losses[13] attributed to PV generation for various PV penetration levels (x-axis) without DR (Losses) and with DR (Losses[DR]). At low PV penetration level, the value is likely to be negative. The savings in losses reduce with further increase in PV installations and at high PV penetration the value may become positive.

DR may improve the reduction in losses, but as the implementation of DR also leads to a smaller network capacity, i.e. higher impedances, losses may not be affected too significantly.

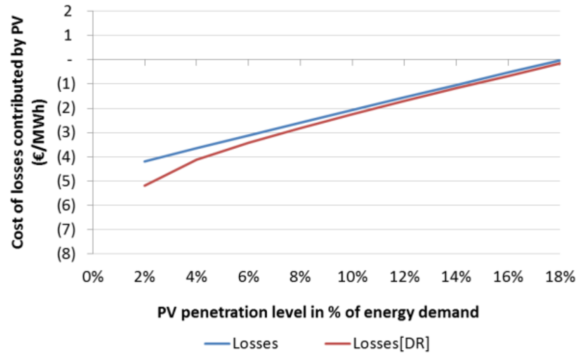


Figure 24 An illustrative graph showing the cost of losses attributed to PV (€/MWh)

The last graph (Figure 25) provides the total grid integration cost of PV without DR(Grid Integration Cost) and with DR (Grid Integration Cost [DR]) as functions of PV penetration levels (x-axis). This includes all system costs attributed to PV that have been analysed so far: (i) additional capacity cost, (ii) EU grid cost, (iii) balancing cost, (iv) distribution network cost, and (v) cost of losses. The total cost is also expressed in €/MWh output of PV.

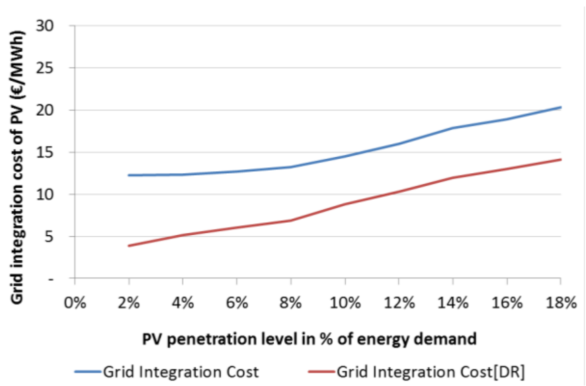


Figure 25 An illustrative graph showing the grid integration cost of PV (€/MWh)

The following sections describe the key results of our studies for each target country.

[13] With an assumption that the average wholesale electricity price is €50/MWh.

4.2 AUSTRIA

By the end of 2012, the installed capacity of PV in Austria was about 418 MW and although the implementation of Feed-in Tariff has boosted the growth of PV in the past few years, its contribution to energy demand is still very modest, less than 1%. However, today's installed capacity has already exceeded the 2020 National Renewable Energy Action Plan (NREAP)'s target (322 MW). The 2020 projection may need to be revised to allow larger contribution of PV to the Austrian's energy supply.

In Austria, the contribution of PV to peak demand is not insignificant especially at low PV penetration. Few of the peak demand conditions occur during daytime; hence it allows PV to contribute at certain extent to the security of supply; however the coincidence factor between the PV peak output and peak demand is not strong as illustrated in Figure 26. As a result, the capacity credit of PV declines rapidly along with increase in its installed capacity. But considering a very small penetration of PV (less than 1% penetration level), the additional generating capacity cost is relatively low (circa €6/MWh).

At low penetration levels, the implementation of DR or storage, by flattening the net electricity demand (load – PV), is not needed as suggested by our analysis (Figure 27). At 6% penetration level, DR becomes more valuable as it can reduce slightly the additional generating capacity cost of PV. Without DR, the additional capacity cost is expected to be within the range of €6/MWh to €13/MWh (at 18% penetration level). With DR, this reduces to €6/MWh - €12/MWh.

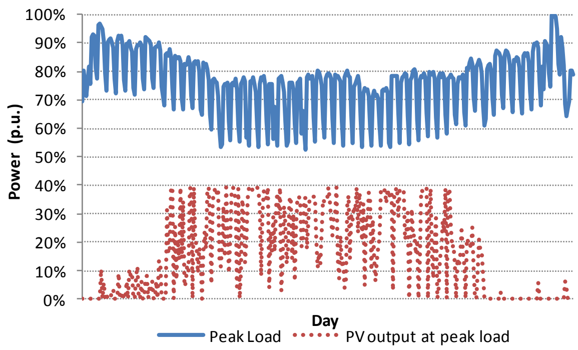


Figure 26 The level of PV output at daily peak demand across one year period in Austria

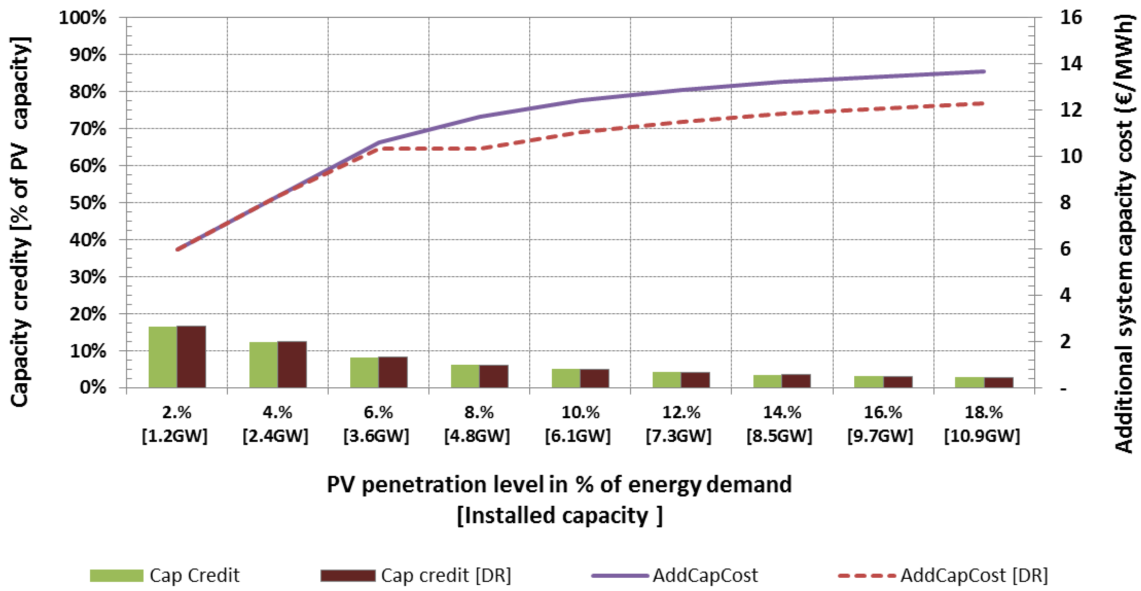


Figure 27 The capacity credit and additional generating capacity cost of PV in Austria

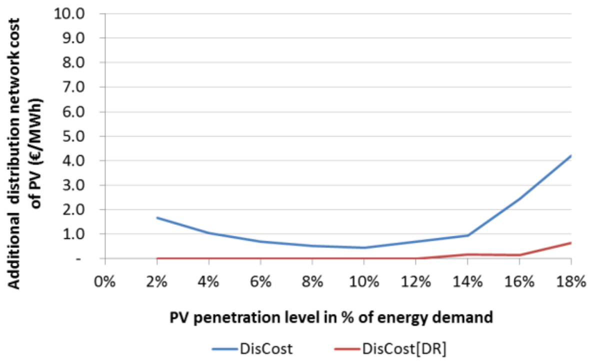


Figure 28 Additional distribution network cost of PV (€/MWh) in Austria

For distribution network, the impact of PV, in term of reinforcement cost, varies from €1.7/MWh at 2% penetration level up to €4.2/MWh at 18% penetration level, as shown in Figure 28.

It is worth to mention that due to the lumpiness of the network investment in the model, one can observe the reduction of cost per MWh when PV's penetration level increases. However, the cost of network always increases with higher penetration of PV due to a requirement for larger network reinforcements.

This additional cost can be successfully mitigated by deploying DR applications, and the results suggest that no additional network reinforcement is required until the PV penetration level reaches 12%. However the application of DR at low penetration level is not required especially when the output of PV already coincides with peak demand.

At the current level, PV in Austria contributes to the reduction in losses. Assuming the average electricity price is €50/MWh, the savings in losses attributed to PV is around €4/MWh. This benefit decreases with further increase in PV installations. At 18% penetration, the net benefit is practically negligible. With DR, the savings can be improved slightly. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 29.

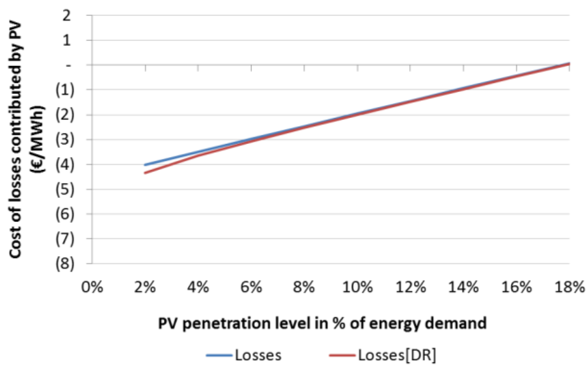


Figure 29 Cost of losses attributed to PV (€/MWh) in Austria

Figure 30 shows the total grid integration cost of PV in the system with and without DR taking into account all cost components. At present, the cost is around €4/MWh and increases to €21.7/MWh when PV penetration in Austria is at 18% penetration level. With DR, the cost can be reduced to €2/MWh - €16.8/MWh.

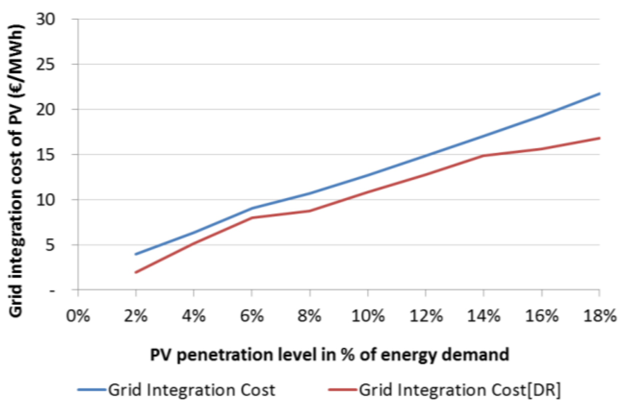


Figure 30 Grid integration cost of PV (€/MWh) in Austria

4.3 BELGIUM

The implementation of Green Certificate (GC) schemes, net-metering for systems below 10 kVA, and the tax credit (until the end of 2011) that allowed individuals to recover some part of PV investment have stimulated PV deployment in Belgium in the recent years. Almost 1 GW of new PV capacity was added on top of 1 GW installed capacity in 2010. Total capacity reached 2.6 GW by the end of 2012. Currently, PV contributes to slightly more than 2% of electricity consumption in Belgium.

This has exceeded, by far, the capacity projection in NREAP. If the PV installation rate of 1 GW/year continues for another 10 years, the installed PV capacity will reach 10 GW - 12 GW in 2020. This will supply 10% to 12% of Belgium's electricity consumption.

However, the contribution of PV to security of supply is relatively small. Peak demand occurs in winter afternoon/evening; hence the contribution of PV without energy storage is small. The coincidence factor between the PV peak output and peak demand is small as illustrated in Figure 31.

As results, the capacity credit of PV is relatively small and declines along with increase in its installed capacity. The additional generating capacity cost, without DR, is expected to be between €9/MWh - €13/MWh.

DR or storage can reduce the cost up to 10% - 15%. The savings for low PV penetration is generally lower than the savings for higher PV penetration levels.

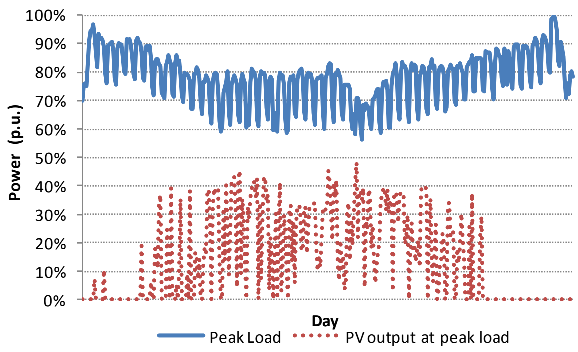


Figure 31 The level of PV output at daily peak demand across one year period in Belgium

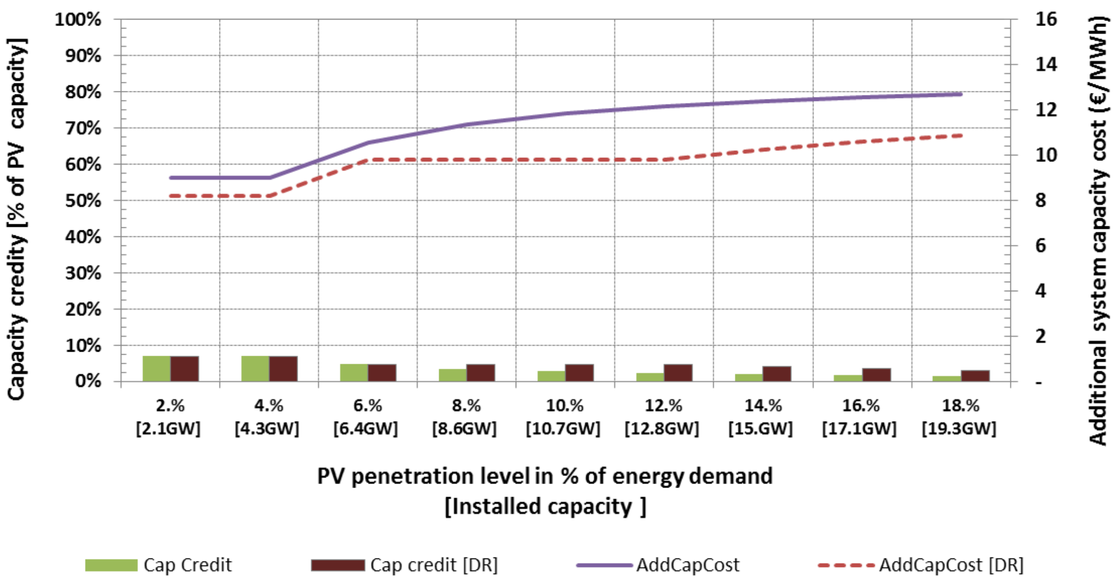


Figure 32 The capacity credit and additional generating capacity cost of PV in Belgium

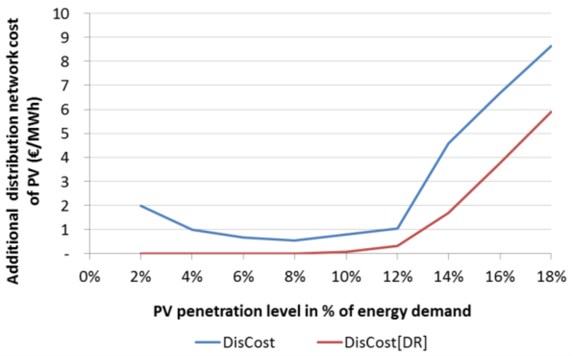


Figure 33 Additional distribution network cost of PV (€/MWh) in Belgium

The additional distribution network cost of PV in Belgium is expected to be between €0.5/MWh and €8.7/MWh (at 18% penetration level). Figure 33 shows the distribution network cost of PV for various PV penetration levels.

At 2% PV penetration level, the distribution network upgrade cost due to PV is circa €2/MWh. Similar to the previous case, due to lumpiness in network reinforcement, further increase in PV system, up to 8% penetration level, reduces the cost down to €0.5/MWh and then the cost increases again for higher penetration levels.

This additional cost can be fully mitigated by deploying DR applications, and the results suggest that no additional network reinforcement is required until the PV penetration level reaches 10%. At 18% penetration level, DR can reduce the distribution network cost due to PV from circa €8.7/MWh to €6/MWh.

At the current level, PV in Belgium contributes to the reduction in losses. Figure 34 shows the savings in losses is around €3.6/MWh. This benefit decreases with further increase in PV installations. At 18% penetration, PV increases losses although the cost is very modest. With DR, the savings can be improved slightly. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 34.

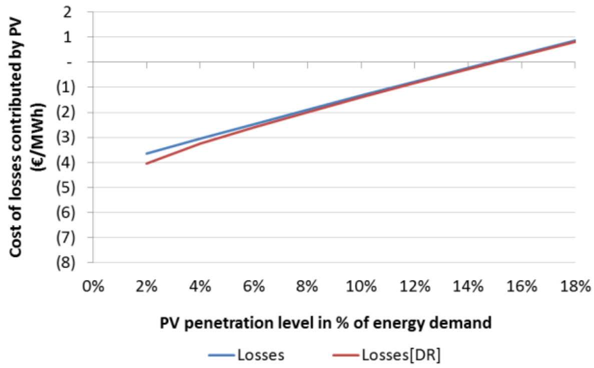


Figure 34 Cost of losses attributed to PV (€/MWh) in Belgium

Figure 35 shows the total grid integration cost of PV with and without DR. The cost is between €7.6/MWh and €26/MWh (at 18% penetration level). With DR, this reduces to €4.5/MWh - €21.5/MWh.

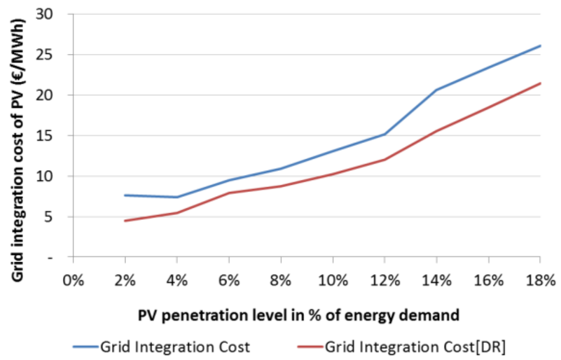


Figure 35 Additional capacity cost and distribution network cost of PV (€/MWh) in Belgium

4.4 CZECH REPUBLIC

Currently, the growth of PV in Czech Republic has been stalled by the reduction of support for new PV deployment after significant, almost 2 GW increase in PV capacity in the period of 2009-2010. By the end of 2012, the total installed capacity was slightly more than 2 GW, supplying around 2% of national electricity demand.

The current capacity already exceeds the NREAP target capacity in 2020 (1.7 GW). As the future of any kind of support for PV is very uncertain, the growth can only be facilitated if there is also a breakthrough in reducing the investment cost of PV and removing the grid barriers or network congestion that has been experienced today.

Considering the relatively low coincidence factor of PV output and peak demand in Czech, as illustrated in Figure 36, the capacity credit of PV in Czech is low (approx. 5%).

Our analysis suggests that the additional capacity cost due to PV in Czech, without DR or storage, is within the range of €10.5/MWh for low penetration and €13.5/MWh for high penetration levels, as illustrated in Figure 37.

The use of DR and storage should be considered to reduce the additional capacity cost. The savings from DR are about 5% (low penetration) to 18% (high penetration).

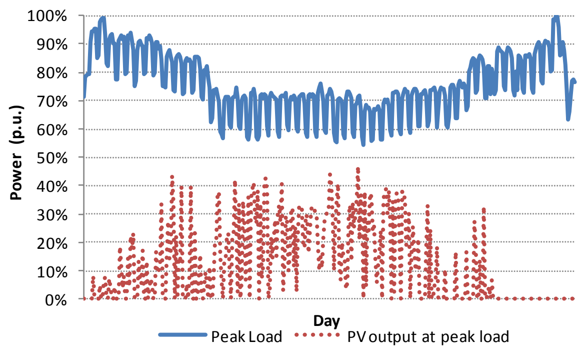


Figure 36 The level of PV output at daily peak demand across one year period in Czech Republic

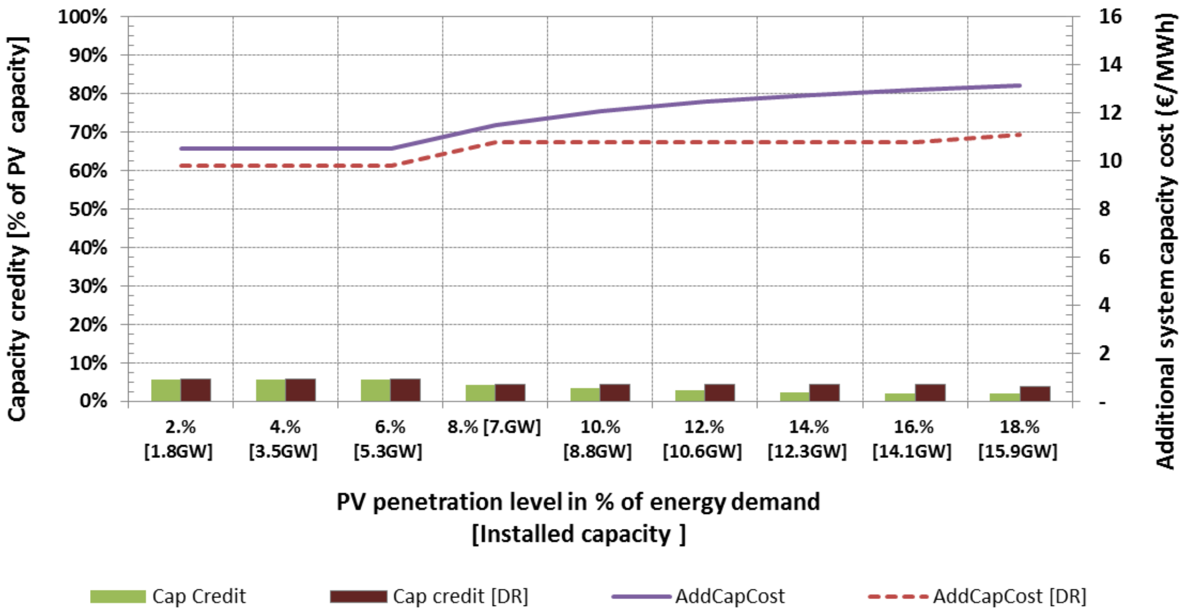


Figure 37 The capacity credit and additional generating capacity cost of PV in Czech Republic

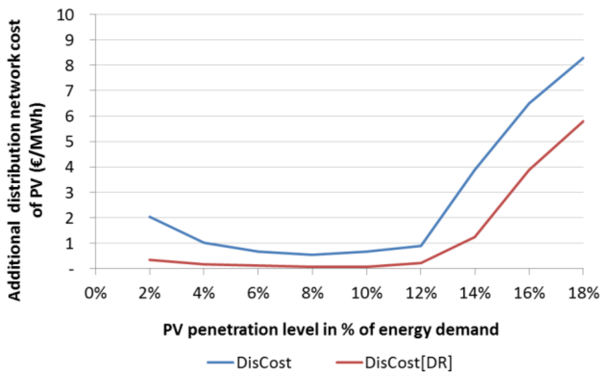


Figure 38 Additional distribution network cost of PV (€/MWh) in Czech Republic

The additional distribution network cost due to PV in Czech Republic is expected between €0.5/MWh and €8.3/MWh (at 18% penetration level). Figure 38 shows the distribution network cost due to PV for various PV penetration levels.

At 2% PV penetration level, the cost of upgrading distribution network due to PV is circa €2/MWh. For higher penetration, up to 8%, the cost decreases to €0.5/MWh at 8% penetration level; however at this point the trend starts to reverse and the cost starts increasing for even higher penetration levels. At 12% penetration level, the cost starts to increase more rapidly due to a requirement for larger network reinforcements.

Up to 10% penetration level, the additional network cost can be successfully mitigated by deploying DR technologies. At 18% penetration level, DR can reduce the distribution network cost of PV from circa €8.3/MWh to €5.8/MWh.

At the current level (2%), PV contributes to the reduction in losses. Figure 39 shows the savings in losses is around €4.4/MWh. This benefit decreases with further increase in PV installations. At 16% penetration, PV starts increasing losses although the cost at 18% penetration level is still very modest. With DR, the savings can be improved but insignificant. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 39.

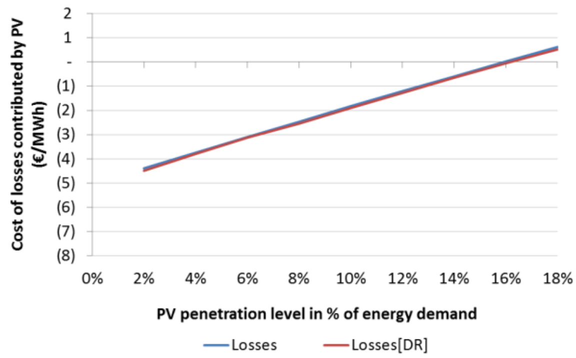


Figure 39 Cost of losses attributed to PV (€/MWh) in Czech Republic

Figure 40 shows the grid integration cost of PV with and without DR. The cost is between €8.5/MWh and €26/MWh (at 18% penetration level). With DR, this reduces to €5.9/MWh - €21.3/MWh.

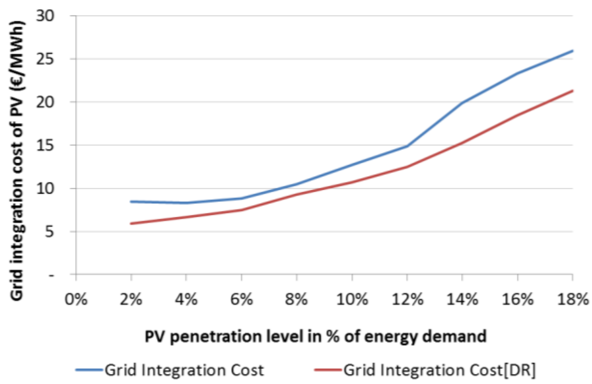


Figure 40 Additional capacity cost and distribution network cost of PV (€/MWh) in Czech Republic

4.5 FRANCE

In the last three years, installed PV capacity has increased significantly. In 2008, the PV capacity was less than 100 MW, but in 2011, it reached 2.7 GW. By the end of 2012, the capacity was 4 GW. This rapid growth can be attributed to the implementation of attractive FiT schemes. However, the contribution of PV to supply electricity load in France is still very modest, less than 1%.

By 2020, the NREAP is projecting 4.9 GW of PV capacity; this requires another 0.9 GW of new PV investment from 2013 until 2020. More ambitious projection by EPIA suggests that France can have 30 GW of PV by 2020. This will provide about 7% of electricity consumption in France.

France has winter evening peak demand and this leads into a very low coincidence factor of PV output and peak demand, as illustrated in Figure 41, and the capacity credit of PV, therefore, is small, 5% or less. Thus, contribution of PV capacity to peak demand security is insignificant.

Our analysis suggests that the additional capacity cost due to PV in France is between €12.4/MWh at low penetration levels and around €15/MWh at high penetration levels, as shown in Figure 42.

The impact of DR or storage to improve the capacity credit of PV and reduce the additional capacity cost is positive. The savings are in the range of 6% (for low penetration) and 20% (for high penetration).

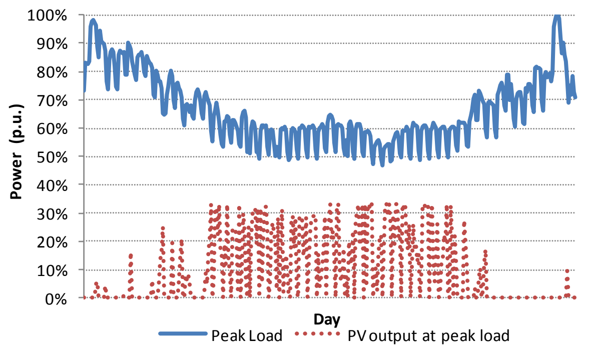


Figure 41 The level of PV output at daily peak demand across one year period in France

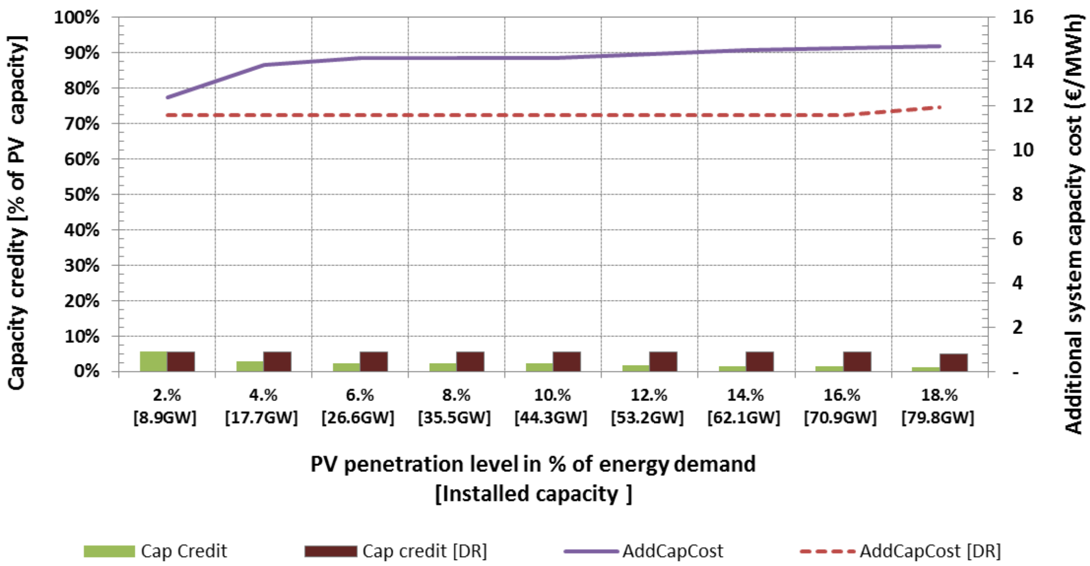


Figure 42 The capacity credit and additional generating capacity cost of PV in France

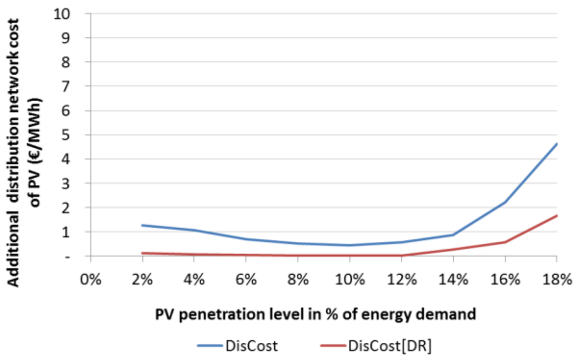


Figure 43 Additional distribution network cost of PV (€/MWh) in France

The additional distribution network cost triggered by PV in France is expected between €0.5/MWh up to €4.6/MWh (at 18% penetration level). Figure 43 shows the distribution network cost due to PV for various PV penetration levels.

At 2% PV penetration level, the cost of upgrading distribution network cost caused by PV is circa €1.3/ MWh. Similar to the previous case, higher penetration of PV, up to 10%, reduces the cost down to €0.5/MWh. However, at this point, the cost starts to increase for higher penetration levels. At 14% penetration level, the cost starts to increase more rapidly due to larger network reinforcement required.

Up to 12% penetration level, the additional network cost can be successfully mitigated by deploying DR applications. At 18% penetration level, DR can reduce the PV driven distribution network cost from circa €4.6/MWh to €1.7/MWh.

At the current level (1%), PV contributes to the reduction in losses. Figure 44 shows the savings in losses is more than €2.5/MWh. This benefit decreases with further increase in PV installations. Even at 18% penetration, PV can still reduce losses although the savings are small. With DR, the savings can be improved but insignificant. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 44.

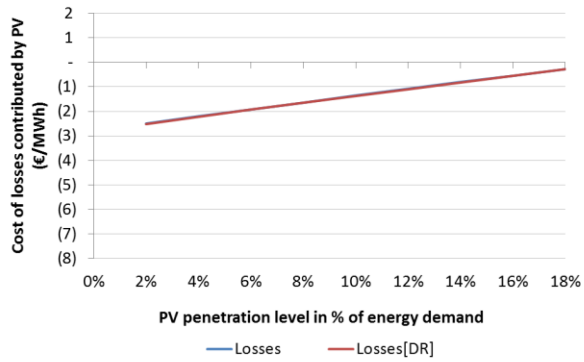


Figure 44 Cost of losses attributed to PV (€/MWh) in France

Figure 45 shows the grid integration of PV in France with and without the implementation of DR. The cost is between €11.5/MWh and €22.9/MWh (at 18% penetration level). With DR, this reduces to €9.5/MWh - €17.2/MWh.

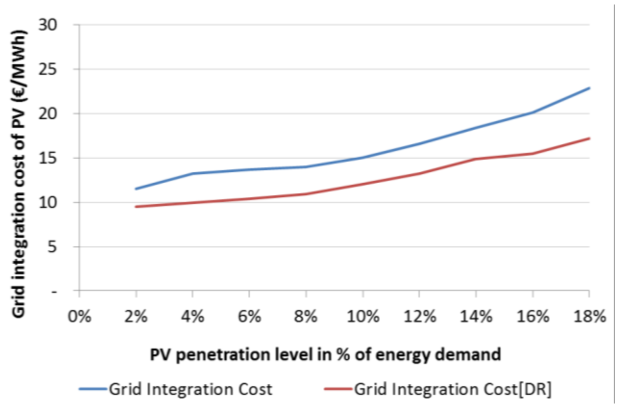


Figure 45 Additional capacity cost and distribution network cost of PV (€/MWh) in France

4.6 GERMANY

There are about 33 GW of PV installed in Germany at present. The strong growth of PV capacity has been facilitated by the implementation of attractive FiT for a number of years. This also supports the development of PV industry in Germany. With its current capacity, PV in Germany can supply almost 5% of its national electricity consumption.

By 2020, according to its NREAP, the installed PV capacity is projected to be around 52 GW, supplying 8% of its national electricity consumption. This penetration level is considered to be the largest amongst other European countries and put Germany as a leader in PV industry,

However, the capacity factor of PV in Germany is low compared to the capacity factor of PV installed in Southern Europe. And as Germany experiences peak demand during winter evening, the coincidence factor of PV output and peak demand is relatively low as shown in Figure 46.

Our analysis (Figure 47) suggests that the additional capacity cost due to PV in Germany is within a narrow range, i.e. € 11.8/MWh - €12.8/MWh. The future PV investment will only contribute to a modest increase in the capacity cost.

DR can improve the capacity credit of PV by 4%; but the impact on the additional capacity cost can be more substantial as it reduces up to 22% of the cost. With DR, the additional capacity cost of PV in Germany is between €9.2/MWh and €10.1/MWh.

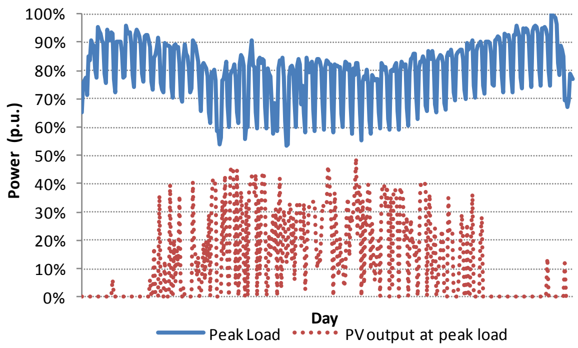


Figure 46 The level of PV output at daily peak demand across one year period in Germany

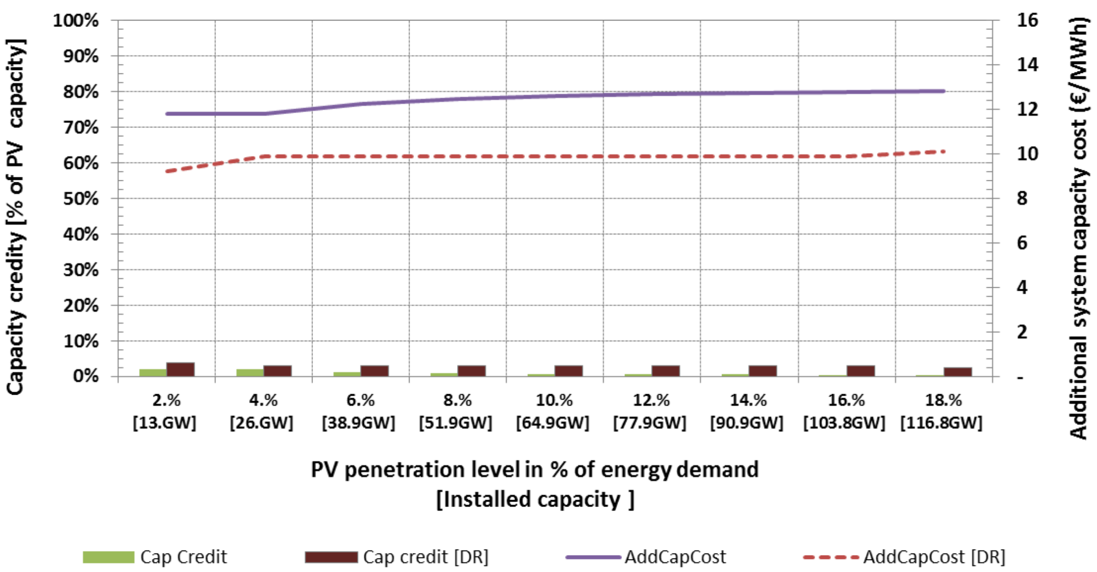


Figure 47 The capacity credit and additional generating capacity cost of PV in Germany

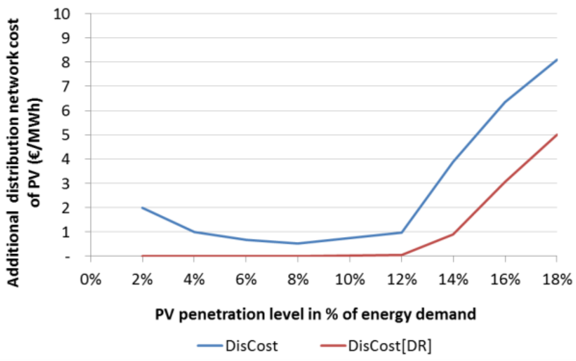


Figure 48 Additional distribution network cost of PV (€/MWh) in Germany

The additional distribution network cost due to PV in Germany is expected between € 0.5/MWh up to €8.1/MWh (at 18% penetration level). Figure 48 shows the PV driven distribution network cost for various PV penetration levels.

At 2% PV penetration level, the distribution network cost of PV is circa €2/ MWh. And similar to the trend in other countries, the cost decreases with higher penetration, up to 8%. At this point the cost is €0.5/MWh and then the trend reverses and the cost starts increasing for higher penetration levels. At 12% penetration level, the cost starts to increase rapidly due to larger network reinforcement required.

Up to 12% penetration level, the additional network cost can be successfully mitigated by deploying DR applications. At 18% penetration level, DR can reduce the distribution network cost of PV from circa €8.1/MWh down to €5.5/MWh.

At the current level (5%), PV in Germany contributes to the reduction in losses. Figure 49 shows the savings in losses is around €3.2/MWh. This benefit decreases with further increase in PV installations. At 18% penetration, the net impact of PV on losses is practically zero (very small). With DR, the savings can be improved slightly. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 49.

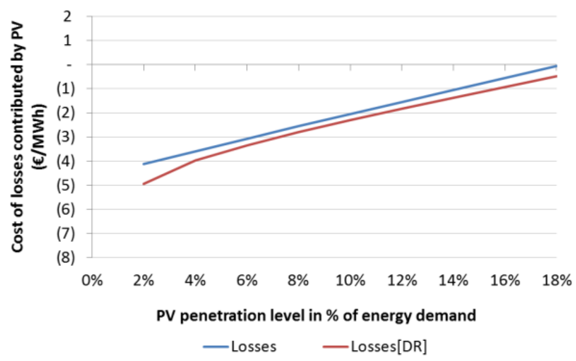


Figure 49 Cost of losses attributed to PV (€/MWh) in Germany

Figure 50 shows the grid integration cost of PV in Germany with and without DR. The cost is between €10/MWh to €24.7/MWh (at 18% penetration level). With DR, the cost can reduce to €4.6/MWh - €18.5/MWh.

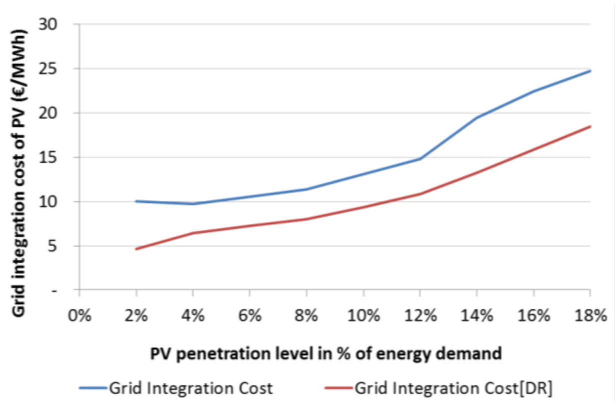


Figure 50 Additional capacity cost and distribution network cost of PV (€/MWh) in Germany

4.7 GREECE

Having the most potential solar sources in Europe, the installed capacity of PV in Greece has increased rapidly in the past few years. By the end of April 2013, the installed capacity reached almost 2.5 GW, which supplies more than 5% of its national electricity consumption and has exceeded the NREAP target, i.e. 2.2 GW of PV by 2020. Even under austerity measures, the growth rate of PV in Greece is very promising; indicating significant interest in the investment of this technology. EPIA projects that Greece can potentially have 8 GW of PV by 2020 that supplies around 18% of their national electricity demand.

As the peak demand in Greece is driven by loads during summer day, which coincide with the peak output of PV (see Figure 51), the capacity credit of PV is high and PV can displace the capacity of conventional generating capacity. At around 9% penetration level, the cost will become positive but still relatively low compared to the cost in other EU Member States.

As indicated by Figure 52, at low PV penetration levels, the application of DR for flattening load is not required as the PV output already has a strong correlation with peak demand. However DR can bring system benefits when the penetration of PV reaches 9% or higher.

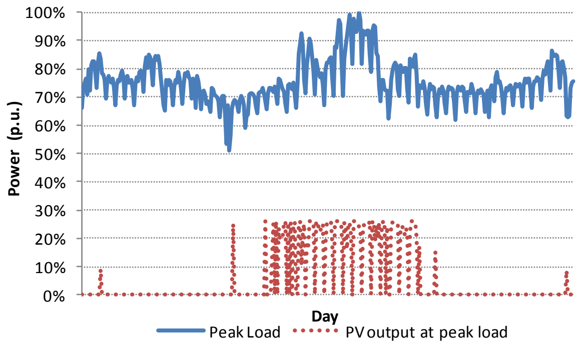


Figure 51 The level of PV output at daily peak demand across one year period in Greece

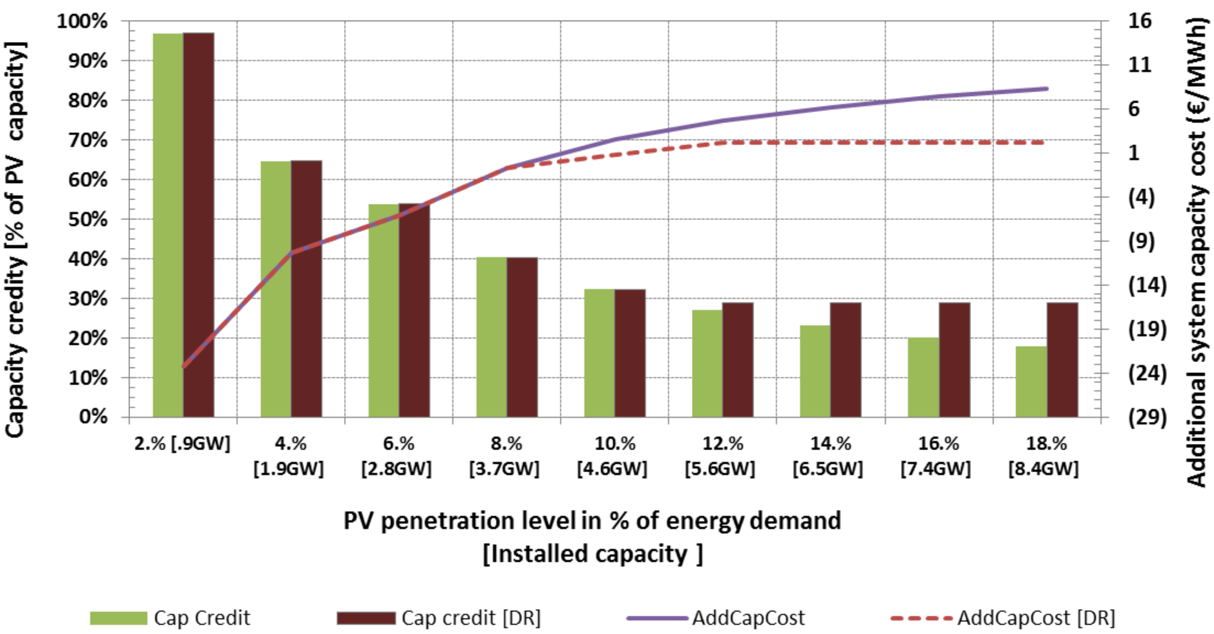


Figure 52 The capacity credit and additional generating capacity cost of PV in Greece

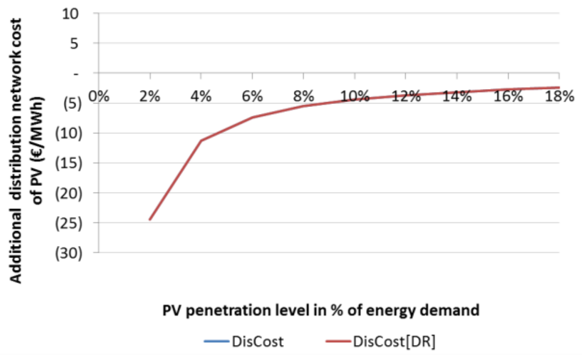


Figure 53 Additional distribution network cost of PV (€/MWh) in Greece

Greece is one of the best candidates among other European countries for PV deployment, as the installation of new PV reduces peak load and releases network capacity which in turn it decreases distribution network cost. The distribution network cost of PV in Greece is negative indicating the benefits/savings that PV can make. This is illustrated in Figure 53. In this context, these savings diminish the need for DR. This is in contrast to other European countries especially the Northern European where DR can contribute significantly to reduce the system cost of PV.

At the current level (5%), PV contributes to the reduction in losses. Figure 54 shows the savings in losses is around €2.5/MWh. This benefit decreases with further increase in PV installations even up to 18% penetration level. With DR, the savings can be improved slightly. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 54.

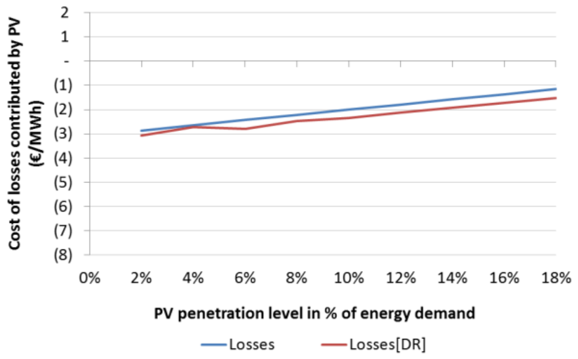


Figure 54 Cost of losses attributed to PV (€/MWh) in Greece

The total grid integration cost of PV is negative up to 10% penetration level and considerably lower for higher penetration than the rest of Europe, as presented in Figure 55. Similar to others, the cost tends to increase with higher PV penetration levels. It is also important to note that since the distribution of PV in Greece is not uniform, some parts with higher PV concentration may experience higher grid costs.

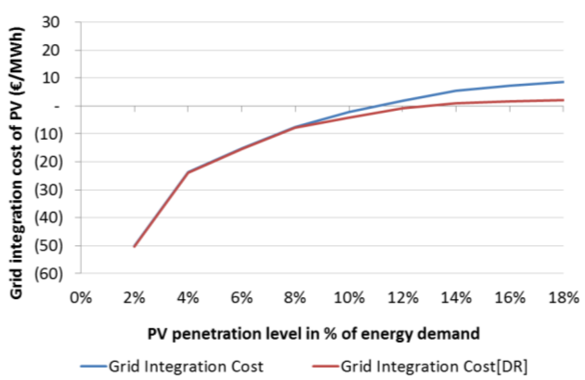


Figure 55 Additional capacity cost and distribution network cost of PV (€/MWh) in Greece

4.8 ITALY

The implementation of FiT schemes in 2008 had led to a boom in PV installations in Italy. In 2008, there were about 400 MW PV capacity and by the end of 2012, the capacity was 16.4 GW; more than 40 times of installed capacity in 2008 and it has exceeded, by 8.4GW, the NREAP target in 2020 (8GW). With such capacity, PV in Italy supplies around 7% of national electricity consumption. EPIA projects that the capacity of PV in Italy can reach 42 GW by 2020.

Our data suggests that the peak demand in Italy is driven not only by summer day loads but also winter evening loads, as illustrated in Figure 56. This limits the contribution of PV to peak demand security indicated by relatively low capacity credit (10% or less) as shown in Figure 57.

Our analysis suggests that the additional capacity cost due to PV in Italy without DR is between €9.6/MWh at low penetration levels and €13.4/MWh at high penetration levels.

In order to improve the capacity credit of PV and subsequently to reduce the additional capacity cost, the use of DR and storage should be considered. DR can improve the capacity credit of PV by 10%; the impact on the additional capacity cost can be more substantial as it reduces more than 50% of the cost.

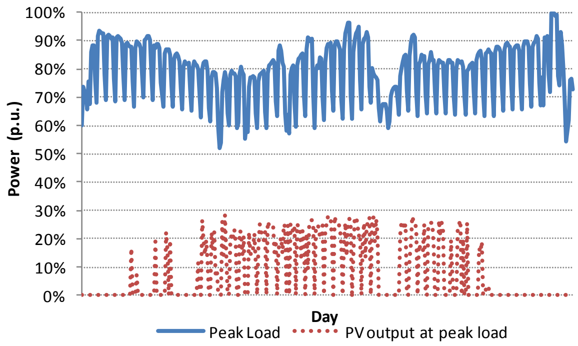


Figure 56 The level of PV output at daily peak demand across one year period in Italy

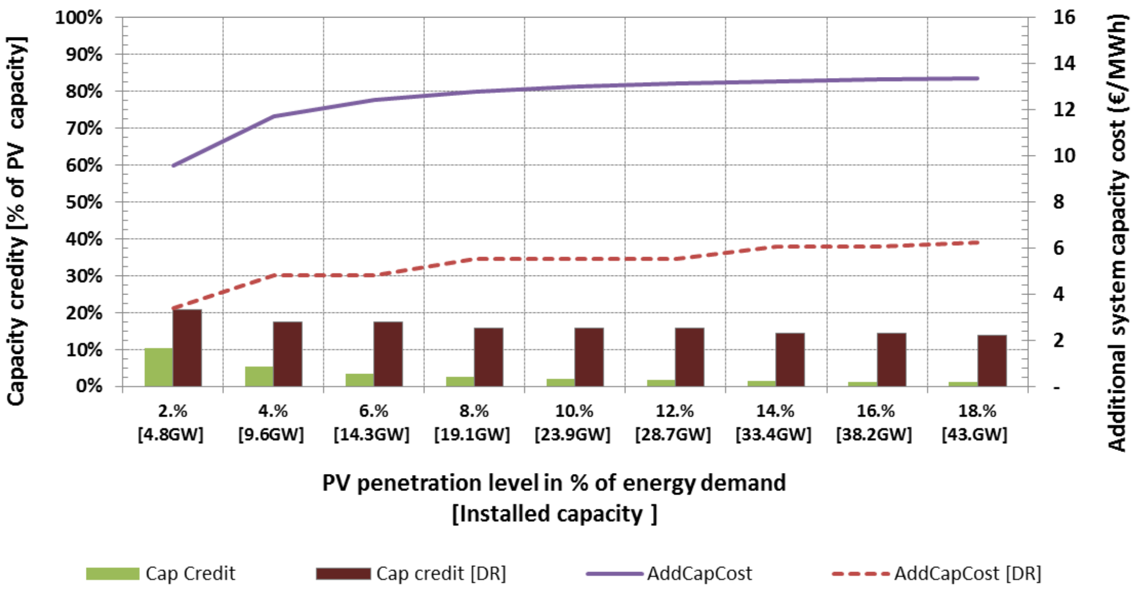


Figure 57 The capacity credit and additional generating capacity cost of PV in Italy

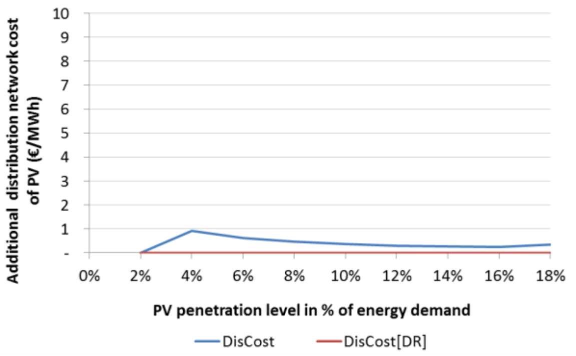


Figure 58 Additional distribution network cost of PV (€/MWh) in Italy

The additional distribution network cost of PV in Italy is very low and the maximum cost is expected around €0.9/MWh. Figure 58 shows the distribution network cost of PV for various PV penetration levels in Italy.

At 2% PV penetration level, there is no reinforcement requirement due to new PV connections in distribution network. However, at 4% penetration level PV will trigger some network reinforcements; this increases the cost to €0.9/MWh. Similar to the previous case, due to lumpiness in network reinforcement, further increase of PV system, up to 16% penetration level, reduces the cost down to €0.25/MWh and then the cost increases again for higher penetration levels.

Up to 18% penetration level, the additional network cost can be successfully mitigated by deploying DR applications especially for managing demand in winter period.

At the current level (7%), PV reduces distribution network losses in Italy. Figure 59 shows the savings in losses is around €3.67/MWh. This benefit decreases with further increase in PV installations. With DR, the savings can be improved. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 59.

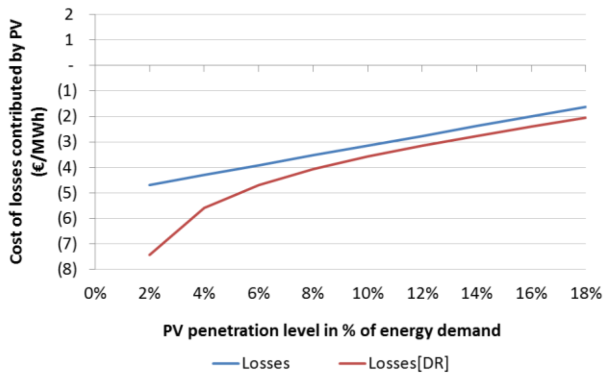


Figure 59 Cost of losses attributed to PV (€/MWh) in Italy

Figure 60 shows the grid integration cost of PV in Italy with and without the implementation of DR. The cost is between €5.2/MWh and €15.9/MWh (at 18% penetration level). With DR, this reduces to - €3.7/MWh (savings) - €6.2/MWh.

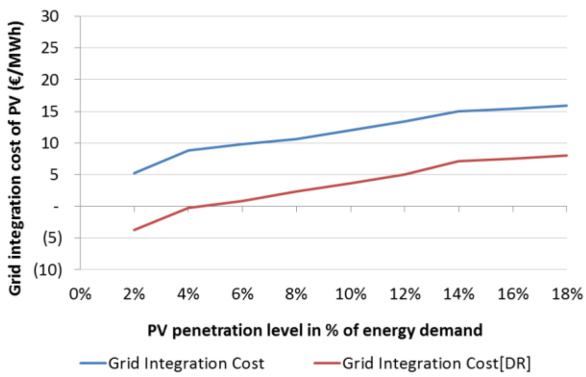


Figure 60 Additional capacity cost and distribution network cost of PV (€/MWh) in Italy

4.9 PORTUGAL

Similar to some other European member states where the financial crisis affected considerably the economic growth, the growth of PV in Portugal has been stalled by the fall of support for new PV deployment after around 183 MW increase in PV capacity in the period of 2007-2011. By the end of 2012, the total installed capacity was 244 MW. This is relatively surprising given the solar potential in Portugal.

The current capacity is still far below the NREAP target capacity in 2020 (1GW). By 2020, if the target is met, PV will contribute to around 3% of electricity consumption and at this level the grid impact of PV will become more apparent.

As our data suggest, the peak demand conditions in Portugal are (surprisingly) driven by cold winter conditions rather than by sunny summer days, the coincidence factor of PV output and peak demand in Portugal is relative low, as illustrated in Figure 61. Consequently, the capacity credit of PV in Portugal is negligible and the contribution of PV capacity to peak demand security is low.

Our analysis suggests that the additional capacity cost due to PV in Portugal is about €15.8/MWh flat across all penetration levels, as illustrated in Figure 62.

In order to improve the capacity credit of PV and subsequently to reduce the additional capacity cost, the use of DR and storage should be considered. DR can improve the capacity credit of PV by 12%-15%; the impact on the additional capacity cost can be more substantial as it reduces up to 50% of the cost.

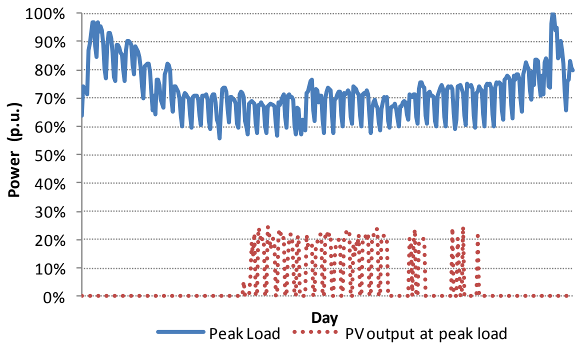


Figure 61 The level of PV output at daily peak demand across one year period in Portugal

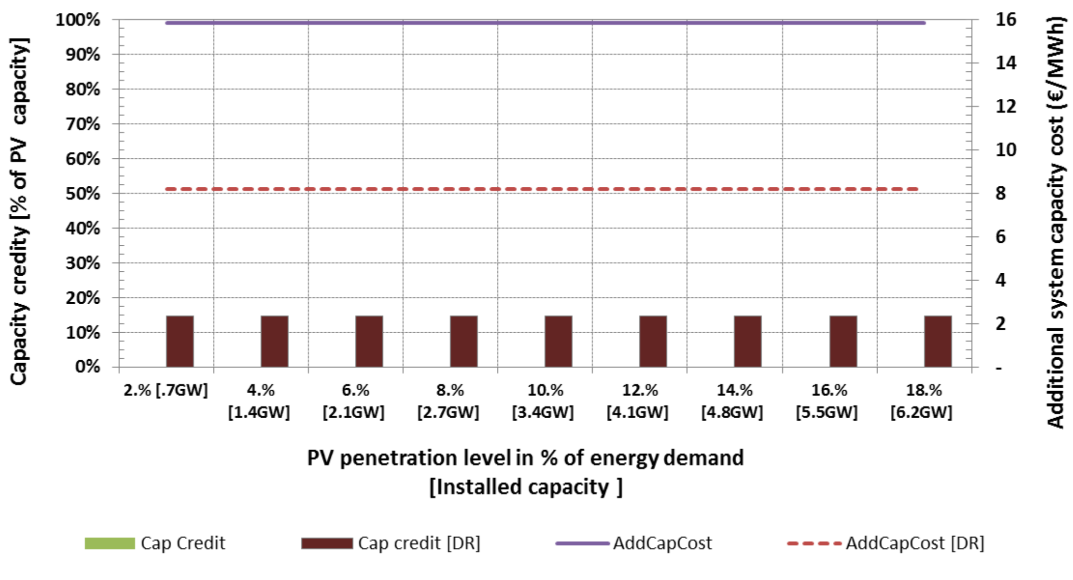


Figure 62 The capacity credit and additional generating capacity cost of PV in Portugal

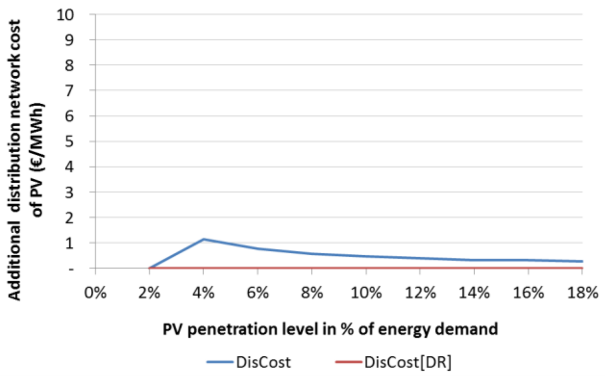


Figure 63 Additional distribution network cost of PV (€/MWh) in Portugal

The additional distribution network cost of PV in Portugal is very low and the maximum cost is expected around €1.2/MWh. Figure 63 shows the PV driven distribution network cost for various PV penetration levels in Portugal.

At 2% PV penetration level, there is no reinforcement requirement due to new PV connections in distribution network. However, 4% penetration level will trigger some network reinforcements; this increases the cost to €1.2/MWh. The cost per MWh of PV output continues decreasing until it reaches the 18% penetration level, reduces the cost down to €0.28/MWh.

Up to 18% penetration level, the additional network cost can be successfully mitigated by deploying DR applications especially for managing demand in winter period.

At the current level (less than 1%), PV reduces network losses in Portugal. Figure 64 shows the savings in losses is more than €3/MWh. This benefit decreases with further increase in PV installations. With DR, the savings can be improved slightly. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 64.

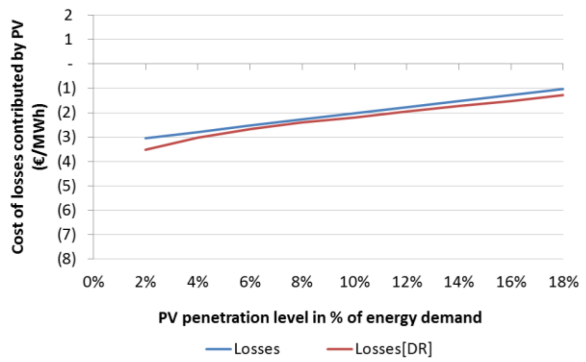


Figure 64 Cost of losses attributed to PV (€/MWh) in Portugal

Figure 65 shows the grid integration cost of PV with and without DR. The cost is between €13.1/MWh to €19/MWh. With DR, this reduces to €5/MWh - €10.8/MWh.

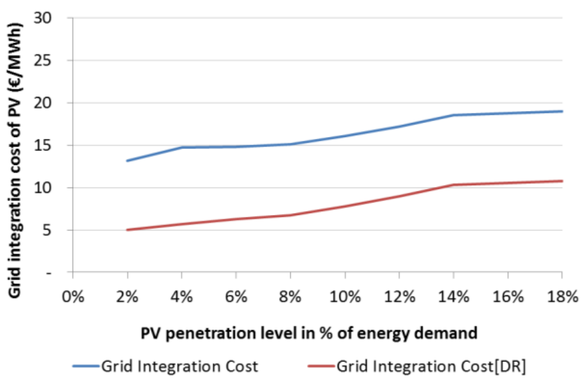


Figure 65 Additional capacity cost and distribution network cost of PV (€/MWh) in Portugal

4.10 SPAIN

The installed capacity of PV in Spain had increased more than 35 times (155 MW in 2006 to 5.2 GW by end of 2012) for the past five years, steamed by generous incentives. Amidst financial crisis and changes in FiT, the rate of new PV installations has slowed down. Spain also suffers lack of interconnection with Europe which limits the ability of Spanish system to integrate larger amount of new PV in their electricity system.

With today's capacity PV has supplied slightly more than 2% of Spanish electricity consumption. This capacity needs to be doubled by 2020 if the NREAP target (8.4 GW) is going to be met, or more than tripled for the EPIA projection (18 GW) to be realised.

In Spain, our data indicate that the peak demand conditions are driven both by air-conditioning loads for heating in winter and cooling in summer (Figure 66). While peak demand in summer coincides with PV output, the contribution of PV for peak demand in winter is modest.

This limits the capacity credit of PV as shown in Figure 67. Our analysis suggests that the additional capacity cost due to PV in Spain is within €12.5/MWh - €13.0 /MWh flat across all penetration levels, as illustrated in Figure 67.

In order to improve the capacity credit of PV and subsequently to reduce the additional capacity cost, the use of DR and storage should be considered. DR can improve the capacity credit of PV by more than 10%; the impact on the additional capacity cost can be more substantial as it reduces up to 40% of the cost.

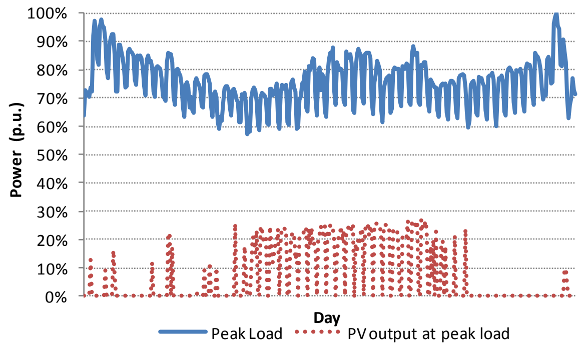


Figure 66 The level of PV output at daily peak demand across one year period in Spain

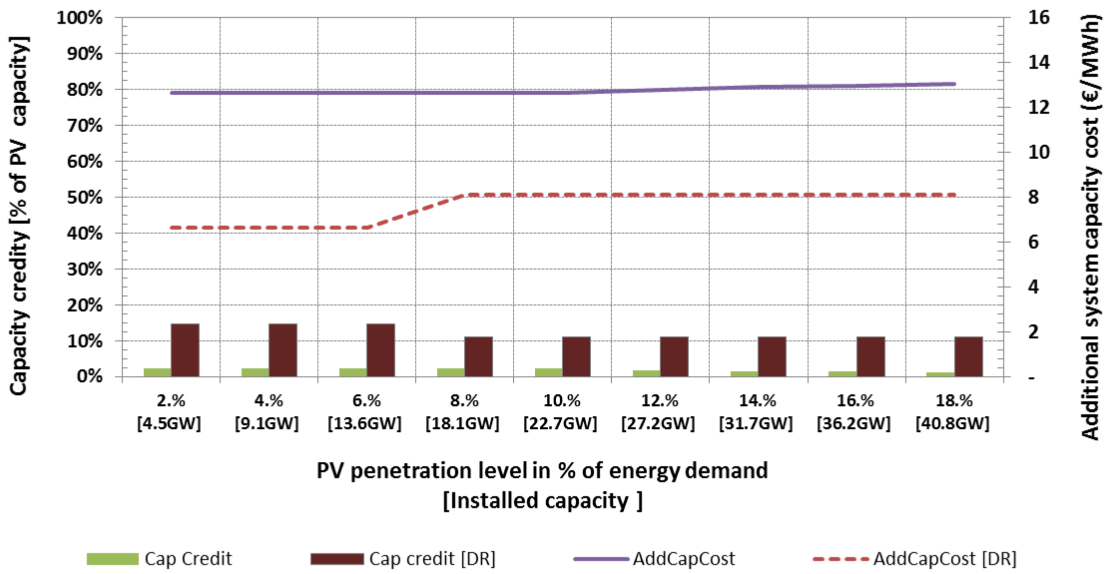


Figure 67 The capacity credit and additional generating capacity cost of PV in Spain

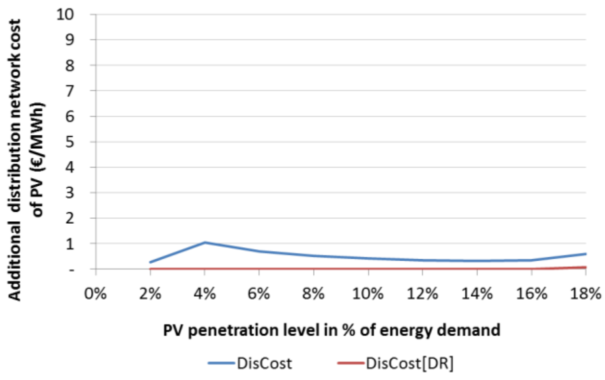


Figure 68 Additional distribution network cost of PV (€/MWh) in Spain

The additional distribution network cost in Spain ranges from €0.28/MWh at 2% penetration level, reaching peak of €1.04/MWh at 4% and constantly decreasing up to 16 %, as shown in Figure 68.

To reduce this additional distribution network cost, the use of DR and storage should be taken in account as it can mitigate fully the cost for all penetration levels up to 18% penetration level. At this level, DR can reduce the cost from 0.6 down to almost zero.

At the current level (2%), PV reduces distribution network losses in Spain. Figure 69 shows the savings in losses is around €5.6/MWh. This benefit decreases with further increase in PV installations. At 18% penetration, the net impact of PV on losses will be practically zero. Beyond this level, PV will start increasing losses. With DR, the savings can be improved but relatively insignificant. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 69.

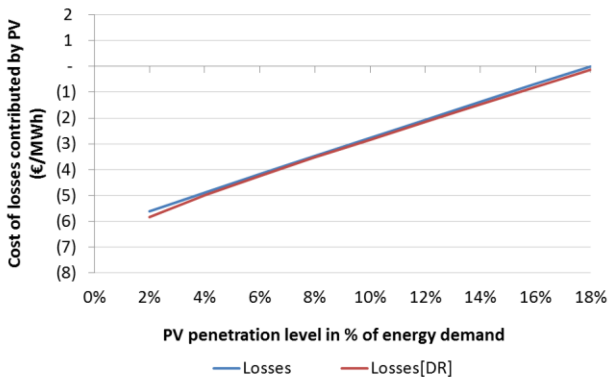


Figure 69 Cost of losses attributed to PV (€/MWh) in Spain

The grid integration cost of PV for various PV penetration levels in Spain with and without the implementation of DR is shown in Figure 70. The cost varies between €7.6/MWh and €17.5/MWh. With DR or storage implementation, the cost can be reduced significantly to €1.1/MWh (low penetration) to €11.9/MWh (high penetration).

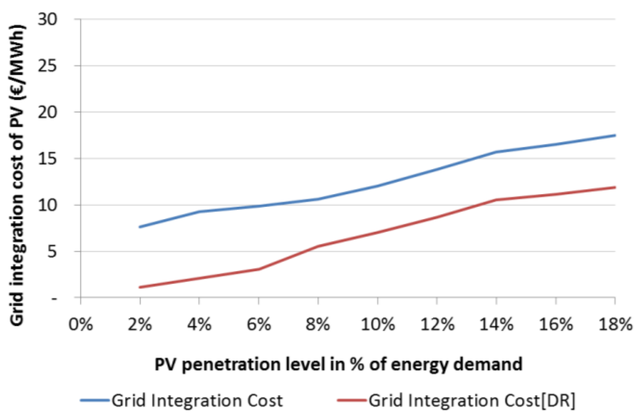


Figure 70 Additional capacity cost and distribution network cost of PV (€/MWh) in Spain

4.11 THE NETHERLANDS

Penetration of PV technology in Netherlands is relatively small. The installed capacity by the end of 2012 was around 270 MW. Although the capacity had increased more than three times compared to the one installed in 2010 (80 MW), its contribution to electricity supply is very modest.

The capacity nowadays is still far smaller than the NREAP target capacity in 2020 (0.7GW) which would supply less than 1% of the country's electricity consumption.

With relatively low load factor and also low capacity credit of PV in Netherlands, its contribution to the future supply system is likely to be modest. As the peak demand conditions in the Netherlands are driven by heating, amongst others, in winter evenings, the contribution of PV output to security is low (Figure 71).

Our analysis suggests that due to low capacity credit, the additional capacity cost due to PV in the Netherlands is between €11/MWh and €13/MWh as illustrated in Figure 72.

In order to improve the capacity credit of PV and subsequently to reduce the additional capacity cost, the use of DR and storage should be considered especially at high PV penetration. DR can improve the capacity credit of PV (5%) although the value is still relatively small. The impact on the additional capacity cost can be more substantial as it reduces up to 5% - 15% of the cost.

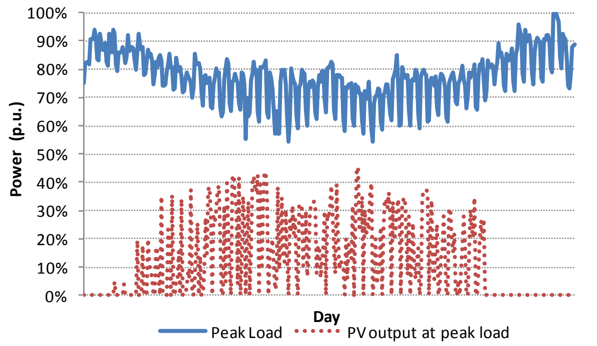


Figure 71 The level of PV output at daily peak demand across one year period in the Netherlands

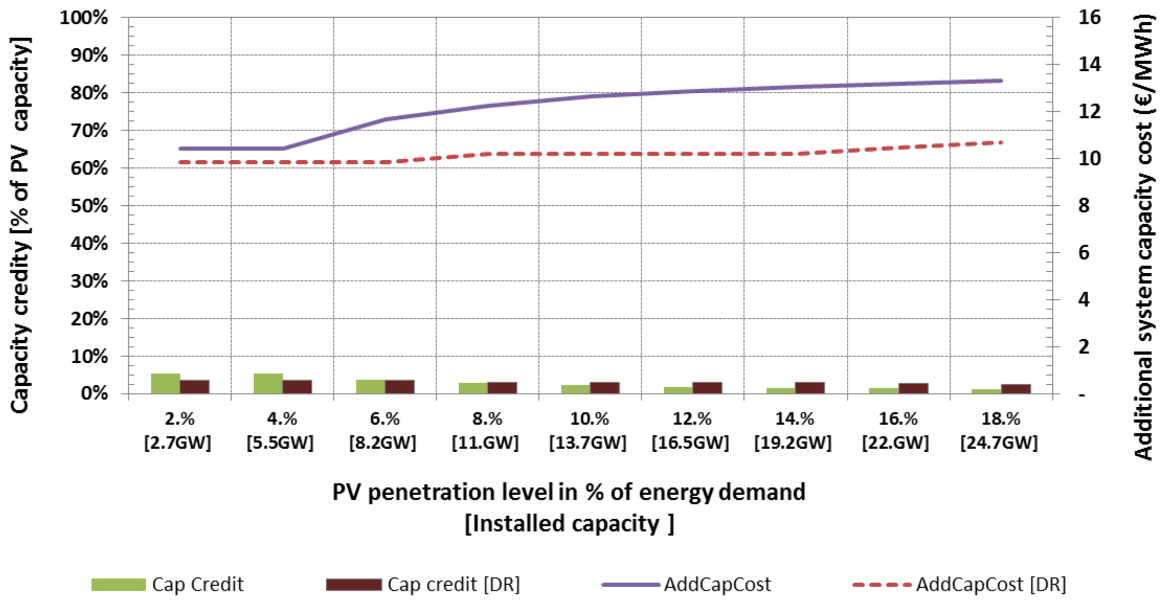


Figure 72 The capacity credit and additional generating capacity cost of PV in the Netherlands

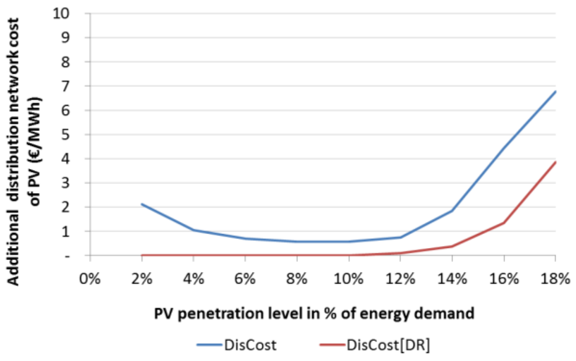


Figure 73 Additional distribution network cost of PV (€/MWh) in the Netherlands

The additional distribution network cost of PV in the Netherlands is expected between € 0.6/MWh and €6.8/MWh (at 18% penetration level). Figure 73 shows the distribution network cost of PV for various PV penetration levels.

At 2% PV penetration level, the distribution network cost of PV is circa €2.1/ MWh. The cost then reduces with higher penetration level, up to 10%. At this point, the cost is down to €0.6/MWh. and then increases again for higher penetration levels. At 12% penetration level, the cost starts to increase rapidly due to larger network reinforcement required.

Up to 12% penetration level, the additional network cost can be successfully mitigated by deploying DR applications. At 18% penetration level, DR can reduce the distribution network cost of PV from circa €6.7/MWh down to €3.86/MWh.

At the current level (1%), PV contributes to the reduction in losses. Figure 74 shows the savings in losses is around €3/MWh. This benefit decreases with further increase in PV installations. At 18% penetration, the net impact of PV on losses will be practically zero. Beyond this level, PV will start increasing losses. With DR, the savings can be improved slightly. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 74.

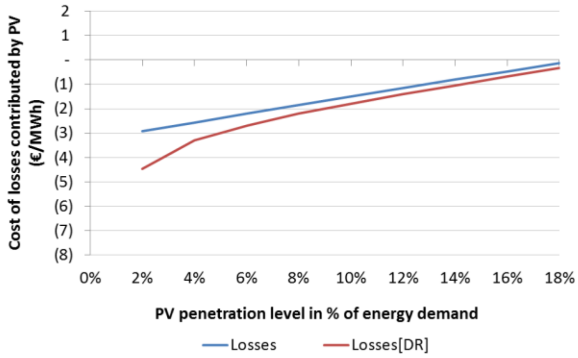


Figure 74 Cost of losses attributed to PV (€/MWh) in the Netherlands

Figure 75 shows the grid integration cost of PV in the Netherlands with and without the implementation of DR or energy storage. Depending on the penetration level of PV, the cost varies between €9.9/MWh and €23.8/MWh. With DR, the cost reduces to €5.7/MWh - €18.1/MWh.

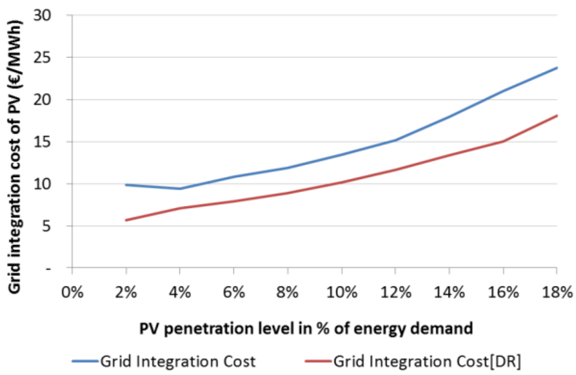


Figure 75 Additional capacity cost and distribution network cost of PV (€/MWh) in the Netherlands

4.12 THE UNITED KINGDOM

Installed capacity of PV in the UK has increased significantly in the past 2 years from around 100 MW in 2010 to more than 1.8 GW by the end of 2012. This rapid deployment has been primarily steamed by generous FiT and other supporting policies.

Amidst financial crisis, the implementation of austerity measures, and progressive reduction of the FiT, the UK is in the good progress of meeting their 2020 NREAP target, i.e. 2.7 GW of PV. Considering the load factor of PV is low, especially in the UK, at today's penetration level their contribution to energy supply is very modest.

Similar to other Northern European countries, the coincidence factor of PV output and peak demand is negligible as illustrated in Figure 76. Consequently, the capacity credit of PV is negligible.

Our analysis suggests that the additional capacity cost due to PV is about €14/MWh flat across all penetration levels, as illustrated in Figure 77.

By shifting the evening loads to morning/afternoon periods, the capacity credit of PV can be improved slightly (up to 5%) and subsequently this can reduce the additional capacity cost. DR can improve the capacity credit of PV by 5%; the impact on the additional capacity cost can be more substantial as it reduces up to 30%-35% of the cost.

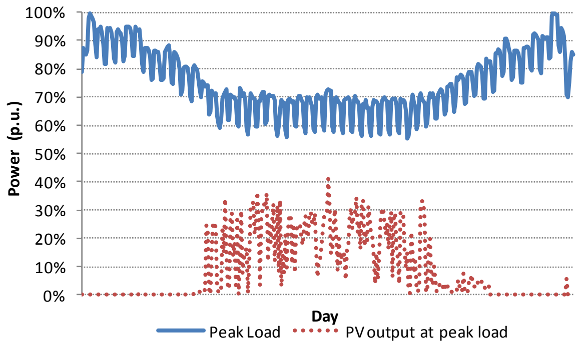


Figure 76 The level of PV output at daily peak demand across one year period in the United Kingdom

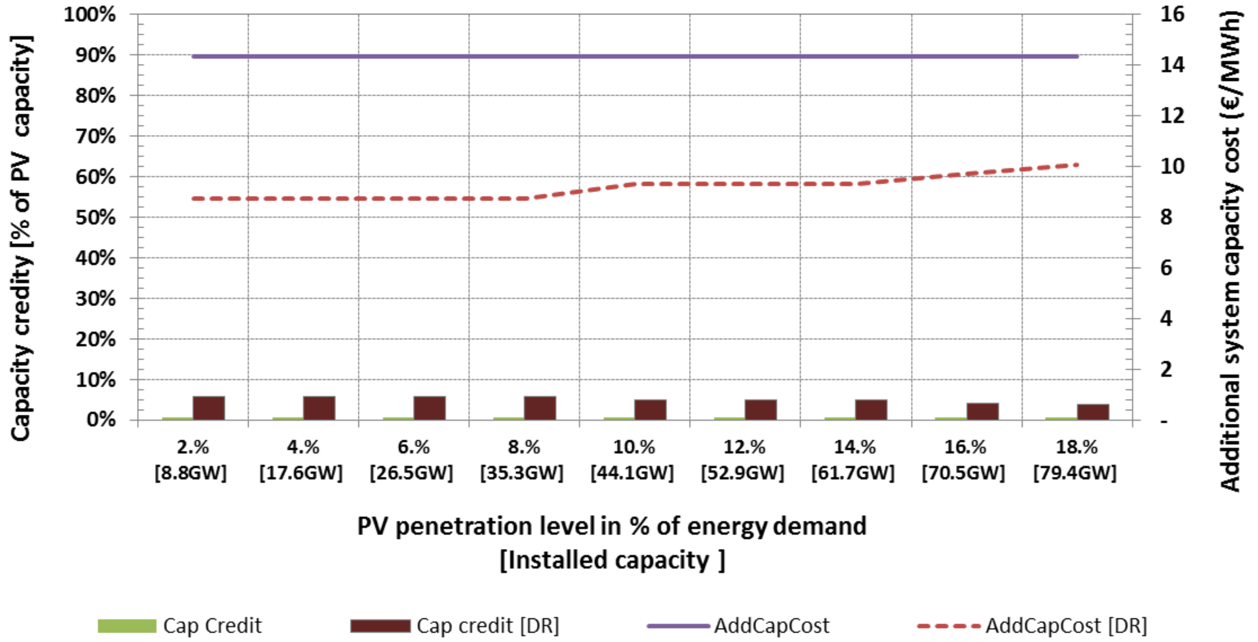


Figure 77 The capacity credit and additional generating capacity cost of PV in the United Kingdom

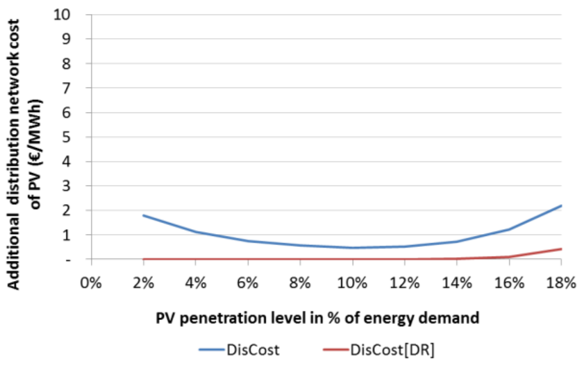


Figure 78 Additional distribution network cost of PV (€/MWh) in the United Kingdom

The additional distribution network cost of PV in the UK is expected between €0.5/MWh and €2.2/MWh (at 18% penetration level). Figure 78 shows the distribution network cost of PV for various PV penetration levels.

At 2% PV penetration level, the distribution network cost of PV is circa €1.8/ MWh. Similar to the previous case, due to lumpiness in network reinforcement, the increased penetration of PV, up to 10% penetration level, reduces the cost down to €0.5/MWh and then the cost increases again for higher penetration levels. At 14% penetration level, the cost starts to increase significantly due to larger network reinforcement required.

Up to 14% penetration level, the additional network cost can be successfully mitigated by deploying DR applications. At 18% penetration level, DR can reduce the distribution network cost of PV from circa €2.2/MWh down to €0.5/MWh.

At the current level, PV contributes to the reduction in losses in the UK. Figure 79 shows the savings in losses is around €4/MWh - €5/MWh. This benefit decreases with further increase in PV installations. At 18% penetration, the net impact of PV on losses will be practically zero. Beyond this level, PV will start increasing losses. With DR, the savings can be improved slightly. The cost of PV on losses for various PV penetration levels with and without DR is shown in Figure 79.

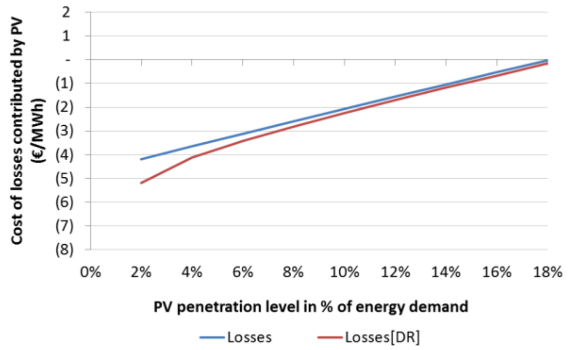


Figure 79 Cost of losses attributed to PV (€/MWh) in the United Kingdom

Figure 80 shows the total grid integration cost of PV in the UK with and without the implementation of DR or energy storage. The cost varies between €12.3/MWh and €20.3/MWh. Implementation of DR technologies can reduce the cost to €3.9/MWh - €14.2/MWh.

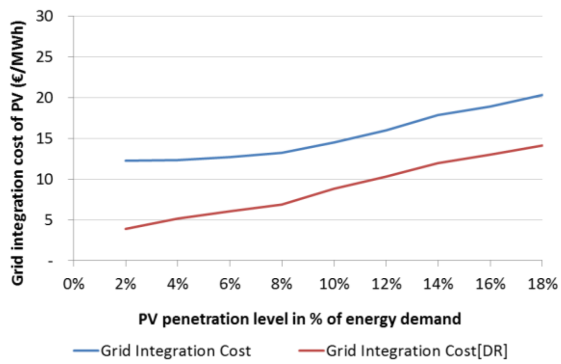


Figure 80 Additional capacity cost and distribution network cost of PV (€/MWh) in the United Kingdom

4.13 EUROPE

The total PV installed capacity in Europe by the end of 2012 was 69 GW. This contributed to about 2% of the European electricity consumption. Based on the NREAP, by 2020 the PV capacity will reach 84.4 GW. More ambitious target by EPIA projects around 250 GW of PV by 2020. This will supply about 6% of European annual electricity demand.

By assuming Europe as a copper plate with no network constraints between the Member States, the peak demand of electricity in Europe is still heavily driven by cold winter evening loads.

As the peak demand occurs typically in cold winter evening, the contribution of PV to peak demand is practically negligible. It can be generically concluded that the contribution of PV capacity to peak demand security in Europe is very modest.

Our analysis suggests that the additional capacity cost due to PV in Europe is circa €14.5/MWh flat across all penetration levels, as illustrated in Figure 81.

In order to improve the capacity credit of PV and subsequently to reduce the additional capacity cost, the use of DR and storage should be considered. DR can improve the capacity credit of PV by 4%- 5%; the impact on the additional capacity cost can be more substantial as it reduces 30%-38% of the cost.

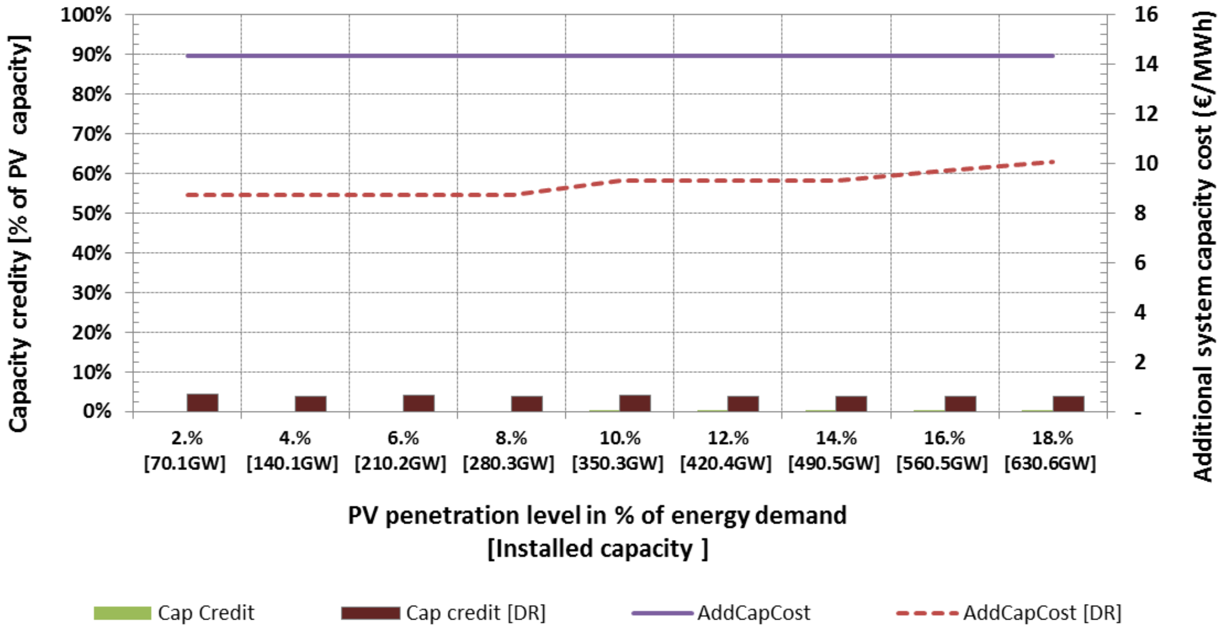


Figure 81 The capacity credit and additional generating capacity cost of PV in Europe

5. Conclusions

5.1 Europe can integrate large PV penetration

Our studies, using PV Parity 2020 and 2030 scenarios with 240 GW and 480 GW installed capacity of PV, respectively, demonstrate that the Grid is able to integrate such large amount of PV. This is in addition to other renewable power generation (wind) and other low carbon generation technologies. The reliability of electricity supply and the economic efficiency of power system operation can still be maintained. This is indicated by a low level (less than 0.4%) of RES curtailment achieved in our simulations.

System integration cost of PV includes costs associated with maintaining security of supply, reinforcements of transmission, distribution networks and increase of generation reserves needed to support real time supply demand balancing. However, some mitigation measures such as the use of Demand Response, storage, smart grid technologies can be used to reduce the system integration costs.

5.2 Cost of PV integration is location specifics

The results of our studies suggest that the grid integration cost of PV is location specifics. It varies from country to country depending on complex interaction between many parameters such as PV characteristics (electricity output profiles, load factors, installed capacity, etc), characteristics of electricity load (magnitude of peak load, load profiles and correlation with PV output), generation portfolio, its connections with neighbourhood regions, designs of the distribution networks, etc.

5.3 The cost in Northern Europe is higher than the cost in Southern Europe

The results of our studies demonstrate that the grid integration cost of PV can reach €26/MWh[14] (this is equivalent to 2.6 Euro cents per kWh). The maximum cost occurs for high penetration of PV (18%) in Northern European countries. For Southern European countries, the cost tends to be lower; the maximum cost is observed around €20/MWh which occurs at a high PV penetration level (18%).

5.4 Additional generating capacity cost is the major component of system integration costs

Additional generating capacity cost of PV reflects the cost of maintaining sufficient generating capacity in the system for security reasons since PV output may not be available during peak demand. For Northern Europe, the cost between €14/MWh - €16/MWh since the capacity credit of PV for this region is very limited due to low coincidence factor between PV output and peak demand. For Southern Europe, the cost is smaller and at low penetration level, the cost can be even negative, e.g. in Greece.

[14] The cost is expressed in Euro per MWh of PV's energy production.

5.5 Additional EU grid cost of PV is relatively low

The ability of an isolated system to integrate large amount of renewables is limited. A strong interconnected system will benefit from diversity of sources and loads, enabling access to the most economic sources, and sharing resources. This in turn will facilitate more efficient integration and capability to absorb more renewable power.

In 2020, when PV penetration level reaches 6.5%, the additional cost to EU grid due to PV is less than €0.5/MWh. By 2030 the cost increases to €2.80/MWh as the PV capacity doubles.

5.6 Balancing cost of PV is low

Due to uncertainty in PV output and its forecast error, additional frequency response and operating reserve services need procuring by the system operator. Our studies suggest that the balancing cost in 2020 is modest, circa €0.5/MWh. The cost increases to €1.04 by 2030.

5.7 Additional distribution network cost of PV is the second major component

Increased PV penetration at distribution systems may trigger network problems (over voltages, thermal overloads, reverse power flows) and the systems may need reinforcing to maintain its security and operation within the statutory limits.

Our analyses suggest that the distribution network cost due to PV at high penetration level (18%) may be up to €9/MWh. Similarly to additional generating capacity cost, we have observed that the distribution network cost in Southern Europe tends to be smaller than the cost in the Northern Europe. This is due to better correlation between peak demand and PV output in Southern Europe.

5.8 At low and medium penetration levels, PV reduces network losses

At low penetration levels, up to 10% energy penetration, PV connected at distribution networks is likely to reduce distribution network losses. Beyond this level, new PV connections may increase network losses. The threshold varies from country to country. Southern Europe where peak demand coincides with PV output is likely to have a higher threshold.

Our analysis suggests that PV can contribute to reduction of losses by 0.25% to 0.75% (of annual energy). Assuming the average wholesale electricity price is €50/MWh, the savings at 2% PV penetration level are between €2.5/MWh and €5.6/MWh of PV output. This can partially compensate the other costs. However the savings diminish with the increased penetration of PV.

5.9 The cost tends to increase along with increased capacity of PV

The grid integration cost of PV is a function of PV penetration levels. It can be concluded from our studies that the higher the penetration level, the cost tends to be higher. This is expected since more deployment of new infrastructure may be needed to accommodate higher PV penetration.

5.10 The integration cost of PV is relatively modest

In comparison to the LCOE of PV, the integration cost of PV, up to 18% penetration level, is relatively modest (circa 15% - 20%). This indicates that the grid integration cost of PV may not have significant impact on the competitiveness of PV.

5.11 Demand Response reduces the grid integration cost of PV

In order to mitigate or to reduce the grid integration cost of PV, the applications of Demand Response (DR) or storage for load shifting has been investigated. The results suggest that DR can reduce significantly the integration cost of PV. The maximum cost with DR is found to be circa €21/MWh; this is about 20% lower than the cost without DR.

One of the key findings suggests that in some Southern European countries such as Greece, the need for DR to support PV is relatively low as there is already a strong correlation between PV output and peak demand conditions.

- End of the report -

.

CONTACTS

PROJECT COORDINATOR
WIP – Renewable Energies
Ms Ingrid Weiss • ingrid.weiss@wip-munich.de • +49 89 7201 2741

or

Energy Futures Lab, Imperial College London
Dr Danny Pudjianto • d.pudjianto@imperial.ac.uk • +44 79 8944 3398