Current and Future Cost of Photovoltaics

Long-term Scenarios for Market Development,
System Prices and LCOE of Utility-Scale PV Systems

STUDY

Agora
Energiewende

Fraunhofer
ISE

Current and Future
Cost of Photovoltaics

Preface

Dear reader,

Since its first application in space missions in 1958, solar photovoltaics technology has come a long way. In Germany, a breakthrough in costs was observed over the last years, following a decade of massive investment in research and deployment. New solar photovoltaic power plants in Germany today cost almost 80 percent less than those built several years ago.

While some industry experts today proclaim the arrival of a "solar age" that will completely change the way how power systems look like in all corners of the world, other experts expect an end in the decline of prices and thus see an end to the "solar bubble." This uncertainty poses a challenge for policy makers, as an evaluation of policy choices often requires analysis of future scenarios, including scenarios for the distant future.

We have therefore asked Fraunhofer ISE to develop scenarios for the future cost development of electricity produced by solar photovoltaics – both under conservative and optimistic assumptions. The results are very interesting indeed – I hope you enjoy reading them.

Yours
Dr. Patrick Graichen
Director Agora Energiewende

Key Insights at a Glance

1. **Solar photovoltaics is already today a low-cost renewable energy technology.**
Cost of power from large scale photovoltaic installations in Germany fell from over 40 ct/kWh in 2005 to 9ct/kWh in 2014. Even lower prices have been reported in sunnier regions of the world, since a major share of cost components is traded on global markets.

2. **Solar power will soon be the cheapest form of electricity in many regions of the world.**
Even in conservative scenarios and assuming no major technological breakthroughs, an end to cost reduction is not in sight. Depending on annual sunshine, power cost of 4-6 ct/kWh are expected by 2025, reaching 2-4 ct/kWh by 2050 (conservative estimate).

3. **Financial and regulatory environments will be key to reducing cost in the future.**
Cost of hardware sourced from global markets will decrease irrespective of local conditions. However, inadequate regulatory regimes may increase cost of power by up to 50 percent through higher cost of finance. This may even overcompensate the effect of better local solar resources.

4. **Most scenarios fundamentally underestimate the role of solar power in future energy systems.**
Based on outdated cost estimates, most scenarios modeling future domestic, regional or global power systems foresee only a small contribution of solar power. The results of our analysis indicate that a fundamental review of cost-optimal power system pathways is necessary.

Contents

1   Key Insights

Our analysis aims at estimating the future cost development of solar photovoltaics to support further discussion

Following the surprising cost development in solar photovoltaics over the last decade, policy makers today are faced with a large uncertainty regarding the future role of this technology. We aim to contribute to a fact-based discussion by providing an analysis of the range of likely long-term cost developments in solar photovoltaics, based on today's knowledge and technologies available today. We start our analysis with the current cost of a ground-mounted solar photovoltaic power plant in Germany, representing one of the most developed markets for photovoltaic power plants worldwide. Based on scenarios of global market developments, ranging from best-case to worst-case scenarios, we then apply the price-experience curve (also known as "learning curve") to estimate future cost developments of solar photovoltaic

modules and inverters. We thereby use a conservative approach that assumes no technology breakthroughs and builds only on technology developments within crystalline silicon technology already known today. Developments of other costs ("Balance of System") are estimated for each component, assuming different scenarios of future module efficiency. The scenarios and estimations were developed by Fraunhofer ISE and discussed and refined intensively at workshops with experts from industry, science and policy.

Building on this in-depth analysis of future investment costs, future ranges of the levelized cost of electricity produced by large-scale solar photovoltaics in different countries are calculated, based on local climatic conditions and cost of capital.

The analysis shows that solar power will soon be the cheapest form of electricity in many regions of the world.

Objective of the study: Provide a range of future cost of PV to support further discussion   Figure E1
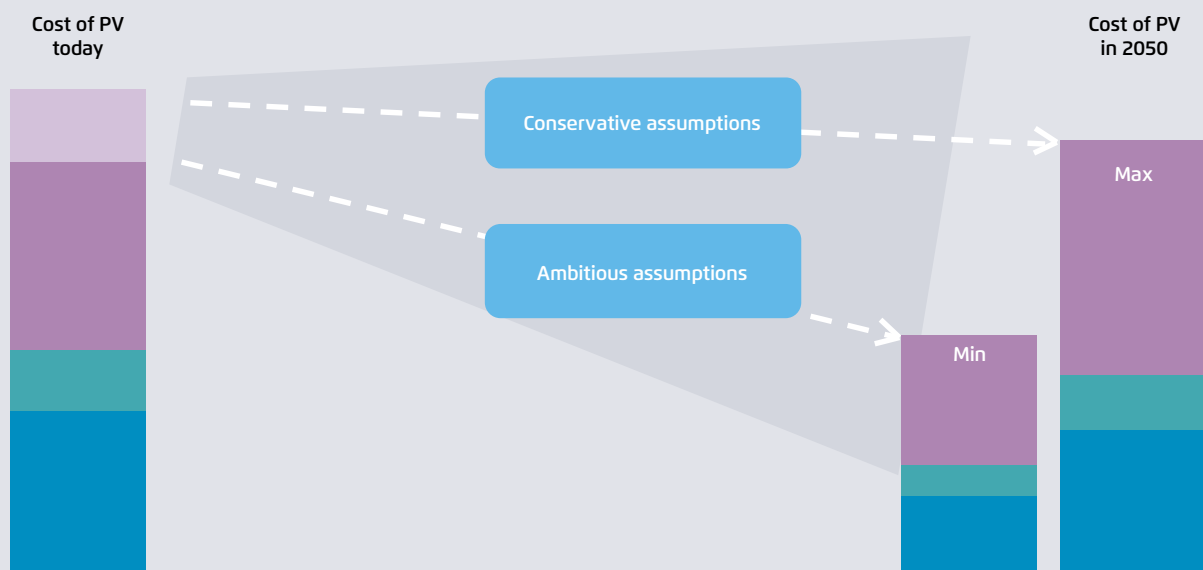
Own illustration

Future module prices in different scenarios based on the historical "learning rate"   Figure E2
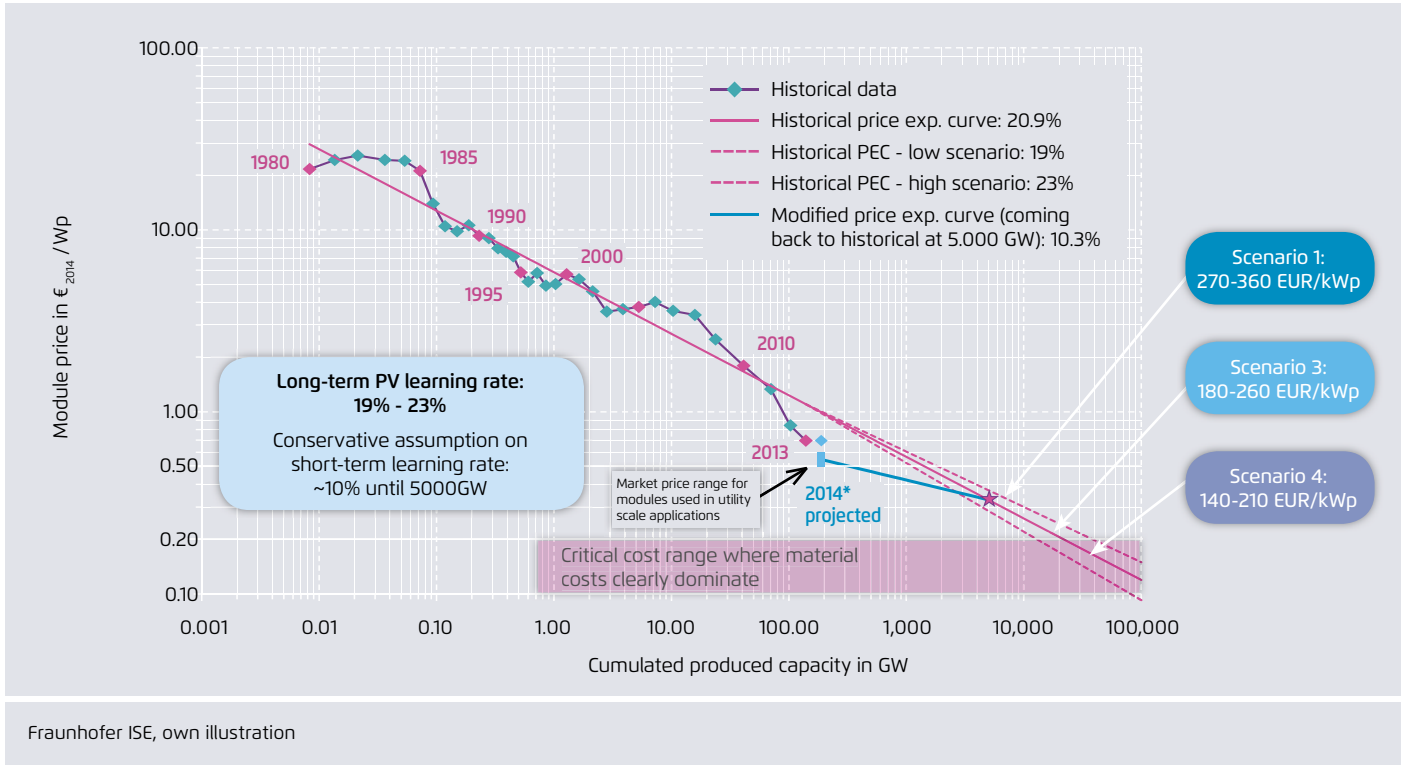
Fraunhofer ISE, own illustration

Solar photovoltaics is already today a low-cost renewable energy technology.

The feed-in tariff paid for electricity from large-scale photovoltaic installations in Germany fell from over 40 ct/kWh for installations connected in 2005 to 9 ct/kWh for those connected in 2014. This sudden reduction came as a major surprise to most industry experts and policy makers. Power produced by solar photovoltaics, long known as one of the most expensive renewable energy technologies, is today cost competitive with both wind onshore and power generated by fossil fuels in Germany. The feed-in tariff for large-scale solar photovoltaic power plants in Germany installed in January 2015 is 8.7 ct/kWh, not adjusted for inflation. This compares to a feed-in tariff for wind onshore, ranging from 6 to 8.9 ct/kWh in Germany, and to the cost of producing power through newly built gas- or coal-fired power plants, ranging from 7 to 11 ct/kWh.

Even lower prices for solar power have been reported in sunnier regions of the world. A power purchase agreement for a 200 MW-solar farm in Dubai was recently signed for 5 ct/kWh (5.84 $ct/kWh). Projects under construction in Brazil, Uruguay and other countries are reported to produce at costs below 7 ct/KWh. These power generation costs largely confirm the notion that the cost of building and operating a large scale solar photovoltaic power plant is comparable around the world, once market barriers are removed. [1]

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1 An estimation shows that the cost of building and operating a solar power plant in Dubai must be approximately equal to projects developed in Germany: while total power output of a solar power plant in Dubai is approximately 70% higher due to higher solar irradiation, the specific cost per unit of power produced is 70% higher in Germany (total cost can be calculated by multiplying the specific cost per unit with the units produced). The applicable cost of capital is roughly comparable between the two countries.

Feed-in tariff for new large-scale solar photovoltaic in Germany   Figure E3

*Nominal values, Feed-in tariff applicable at first of January each year, value 2015 excl. adjustment of 0,4 ct/kWh for direct marketing

German renewable energy law, Agora Energiewende
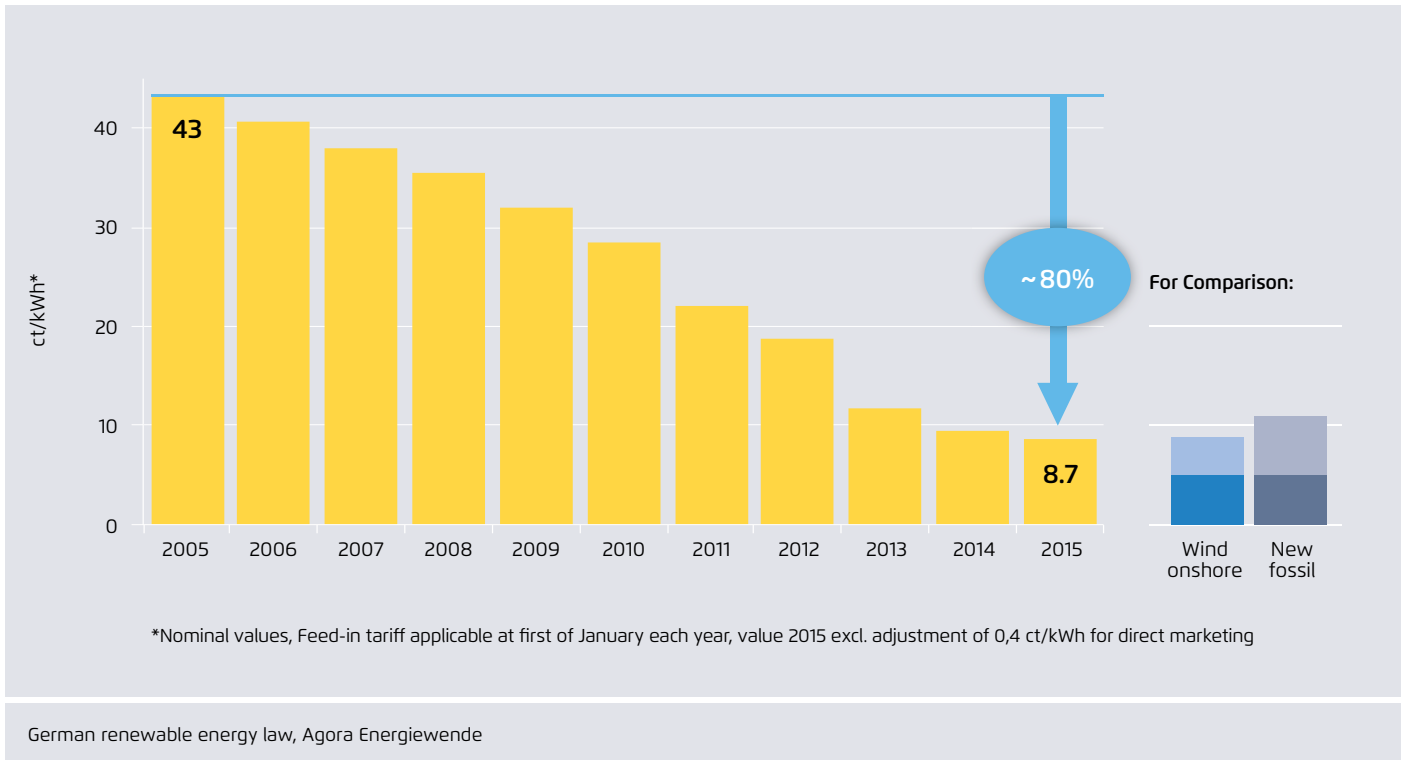
Solar power will soon be the cheapest form of electricity in many regions of the world.

Our analysis of different scenarios concludes that an end to cost reduction for power from solar photovoltaics is not in sight. Even in the most conservative scenarios for market development, without considering technology breakthroughs, significant further cost reductions are expected.

The following methodology was used to reach this conclusion: The starting point of the analysis was to derive consistent scenarios for the global photovoltaics market development between 2015 and 2050. These scenarios were discussed and revised in expert workshops and represent a range from "very pessimistic" to "very optimistic" in terms of global photovoltaics market developments. In the most pessimistic scenario, annual additional photovoltaic installations would increase from ~40 GW in 2014 to 175 GW in 2050 (cumulated produced capacity until 2050 of ~6000 GW). In the most optimistic scenario ("breakthrough scenario"), 1780 GW of photovoltaic systems will be installed

per year by 2050 (cumulated produced capacity by 2050: ~36000 GW).

Based on these market scenarios, future prices for photovoltaic modules were estimated using the "photovoltaic learning curve," which builds on the historic experience that with each duplication in the total number of modules produced, the price per module fell by roughly 20 percent. Based on expert discussions at the workshop, we varied the future learning rate between 19 and 23 percent and introduced the conservative assumption that prices will fall with a learning rate of only roughly 10 percent in the next years, until a total (cumulated) capacity of 5000 GW is produced. This approach results in module costs decreasing from approximately 550 EUR/kW today to 140–210 EUR/kWp by 2050 in the breakthrough scenario, and to 270–360 EUR/kWp in the most pessimistic scenario. A similar approach was applied to estimate the future cost of solar inverters, resulting in investment costs falling from 110 EUR/kWp today to between 23 and 39 EUR/kWp by 2050.

To estimate the future cost of other components ("balance of system cost"), current cost, cost drivers and cost reduction potentials were discussed for each component at the expert workshops and three scenarios for future module efficiency were developed (24, 30 and 35 percent in 2050). Largely driven by increased module efficiency, balance-of-system costs are expected to fall from around 340 EUR/kWp today to between 120 and 210 EUR/kWp by 2050.

The cost of solar generation can be derived on the basis of these figures. Depending on annual sunshine, power costs of 4-6 ct/kWh are expected in Europe by 2025, reaching 2-4 ct/kWh by 2050. For the next decade, this represents a cost reduction of roughly one third below the 2015 level. This near-term price development includes the conservative assumption that module prices will return to the trajectory determined by the historic price-experience curve in our analysis. In the long term, a reduction of roughly two thirds compared to the current cost is expected.

Our analysis has identified increasing module efficiency as a key driver of cost reductions in the long term: The expected duplication of module efficiency until 2050 will allow twice as much power to be produced from the same surface area and thus will reduce the cost of many components (within the balance-of-system cost) by half.

These results indicate that in future, power produced from large-scale solar photovoltaic plants will be cheaper than power produced from any conventional technology in large parts of Europe. The cost of electricity produced in conventional, large-scale power plants typically ranges between 5 and 10 ct/kWh. Cost competitiveness will thus be achieved under optimal conditions before 2025 and full cost competitiveness even under non-optimal conditions by 2050 at the latest. Further research is needed to analyze the cost competitiveness of different technologies in country and regional contexts and at different penetration rates.

Cost of electricity from new solar power plants in Southern and Central Europe — Figure E4

* Real values in EUR 2014; bandwidth represent different scenarios of market, technology and cost development, as well as power plant location between south of Germany (1190 kWh/kWp/y) and south of Spain (1680 kWh/kWp/y); assuming 5% (real) weighted average cost of capital.

Own illustration

Cost of electricity from new solar power plants in North America, Australia, India and Mena region*   Figure E5

2015   2025   2035   2050

North America (1,5 – 5,8)
Australia (1,6 – 4,9)
India (1,6 - 3,7)
Mena (1,6 - 3,7)

ct/kWh*

* Real values EUR 2014; full load hours based on [27], investment cost bandwidth based on different scenarios of market, technology and cost development; assuming 5% (real) weighted average cost of capital.
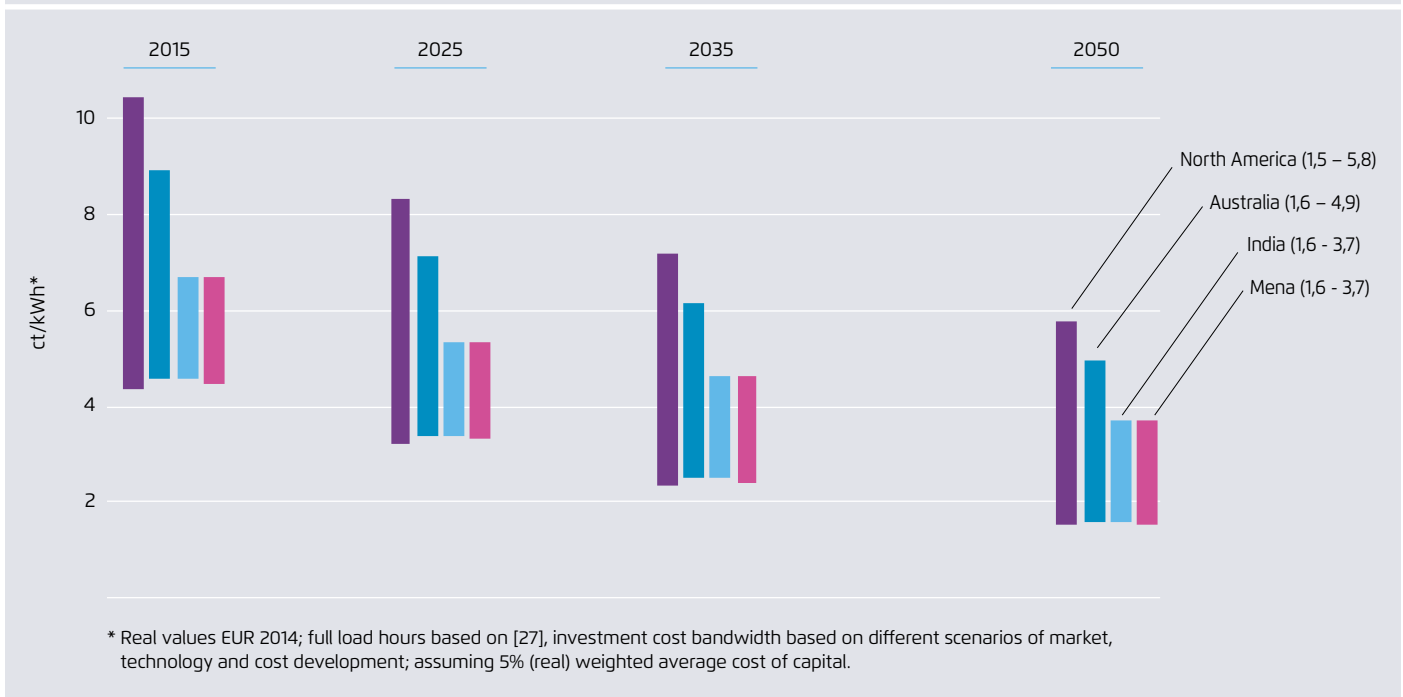
Own illustration

In other regions of the world with higher solar irradiation, solar power will be even cheaper than in Europe. Our results indicate that solar power will become the cheapest source of electricity in many regions of the world, reaching costs of between 1.6 and 3.7 ct/kWh in India and the Mena region (Middle East and North Africa) by 2050. Cost competitiveness with large- scale conventional power plants will be reached in these regions already within the next decade, at a cost for solar power by 2025 ranging between 3.3 and 5.4 ct/kWh.

In North America, costs for large scale solar photovoltaics will reach 3,2 to 8.3 ct/kWh in 2025 and 1.5 to 5.8 ct/kWh in 2050, the wide cost range due to significant geographical differences within the region. In Australia, costs will reach 3.4 to 7.1 ct/kWh in 2025 and 1.6 to 4.9 ct/kWh in 2050. In both regions, cost competitiveness of solar photovolta- ics at the best sites will be reached within the next decade and cost competitiveness for all sites only a number of years later.

In view of the likely cost competitiveness of solar power in many areas of the world, further research is needed, espe- cially on the competitiveness of other energy applications beyond the power sector, such as transport, heating and cooling, as well as the cost competitiveness of power sys- tems with very high shares of photovoltaic power.

Financial and regulatory environments will be key for reducing costs in the future.

The cost of hardware sourced from global markets will de- crease irrespective of local conditions. Solar photovoltaic modules and inverters are traded already today on global markets, similar to commodity products, and costs for other components are similarly global. While regional differences may exist due to the very young nature of utility-scale so- lar photovoltaic markets in different parts of the world, it is very unlikely that large differences in investment costs between different regions of the world will persist in the fu- ture.

Cost of electricity of solar PV at different costs of capital, example southern Germany and
southern Spain in 2025   Figure E6

	Germany	Spain		
WACC:**	5%	5%	7.5%	10%

More sun,
lower cost

Higher cost of capital,
higher cost

* Real values in EUR 2014   ** Weighted average cost of capital

Own illustration
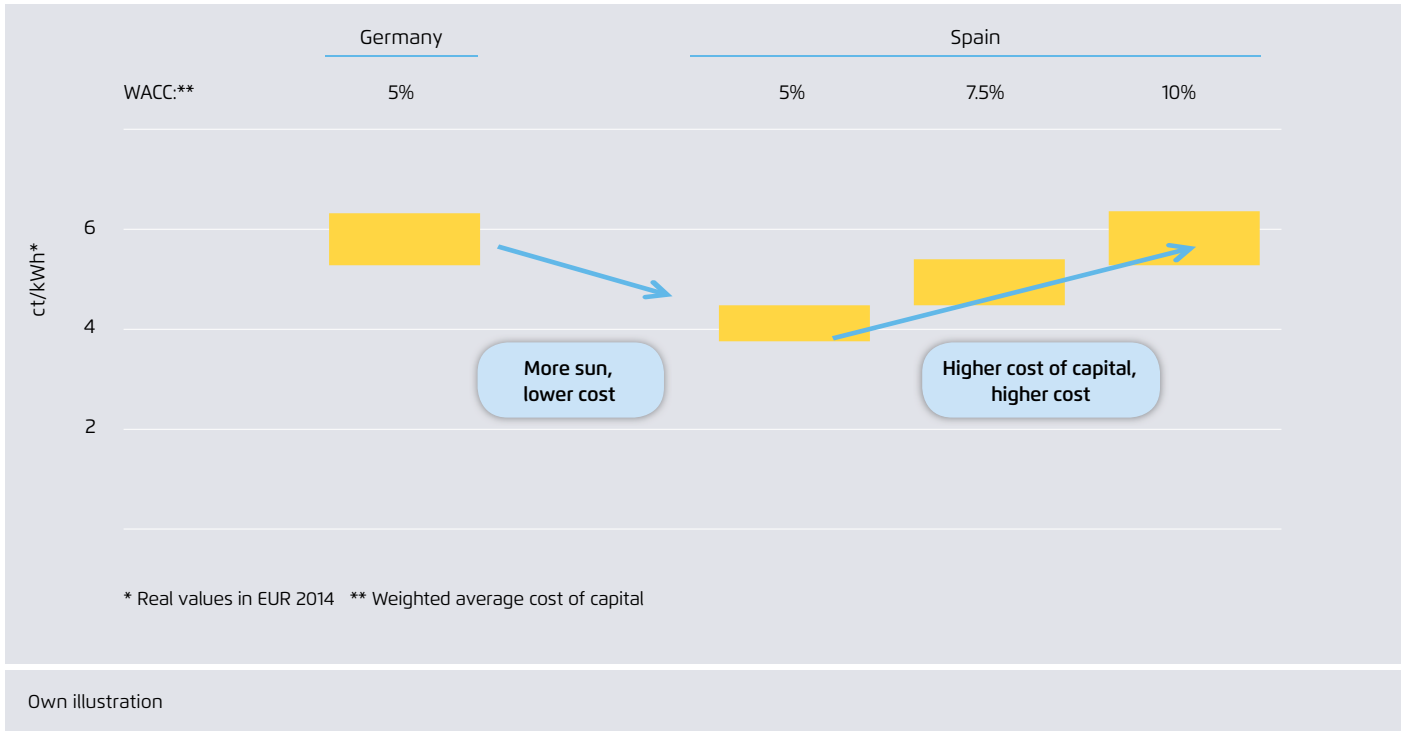
However, the cost of capital is and will remain a major driver for the cost of power from solar photovoltaics. Producing power from solar photovoltaics requires a high up-front investment, but subsequently allows power production for 25 years and more at a marginal cost of close to zero. It is thus a very capital-intensive power-generation technology, and the interest paid on both debt and equity has a large effect on the total cost of a large-scale photovoltaic project.

This effect of different cost of capital may even have a larger impact on power generation cost than the difference in solar resources, which is commonly considered key for the quality of a country's or region's potential to produce power from the sun. Our sensitivity analysis shows that higher cost of capital may increase cost of power by close to 50 percent in an extreme case. In the illustrative example comparing southern Germany and southern Spain, this capital cost effect alone could make solar power prices in southern Germany and southern Spain equal, even though southern Spain has 50 percent more sunshine hours than southern Germany.
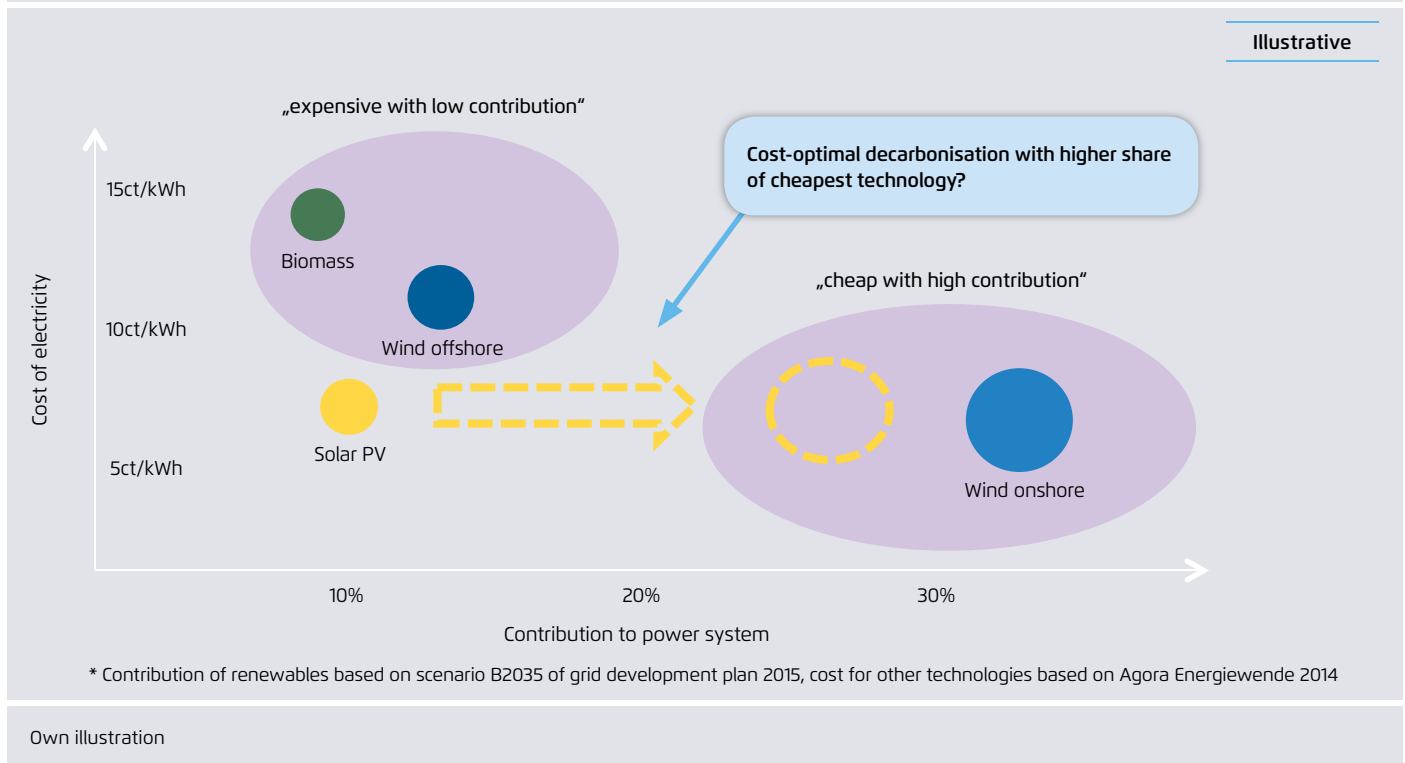
The regulatory environment will thus be key for reducing the cost of power from solar photovoltaics in the future, as the cost of capital is largely driven by the risk perceived by investors. Reliable long-term power purchase agreements help to reduce the cost of capital for project developers, as experiences in Germany and in other countries show. A lack of such long-term contracts or even the fear of retroactive changes in regulatory regimes may lead to a significant increase in cost of capital.

Most scenarios fundamentally underestimate the role of solar power in future energy systems.

A large body of scientific literature, as well as publications by national and international institutions, describe possible developments of future power systems. Most of these scenarios foresee only a small contribution of solar power to future national, regional or global power systems. In many cases this can easily be explained by the use of outdated cost estimates for solar photovoltaics, leading to only a minor

Cost of electricity and contribution to power system per technology, in Germany in 2035*   Figure E7

Illustrative

"expensive with low contribution"

15ct/kWh

Cost of electricity

Biomass

Cost-optimal decarbonisation with higher share of cheapest technology?

Wind offshore

10ct/kWh

"cheap with high contribution"

Solar PV

Wind onshore

5ct/kWh

10%   20%   30%

Contribution to power system

* Contribution of renewables based on scenario B2035 of grid development plan 2015, cost for other technologies based on Agora Energiewende 2014

Own illustration

contribution of solar power in cost-optimal pathways. The massive cost reduction in solar photovoltaic systems in recent years has outpaced most forecasts for the next decade, often just within the time it took to publish a peer reviewed paper.

The results of our analysis indicate that a fundamental review of cost-optimal power system pathways is necessary. While not the only factor, the cost of power production is the key driver that determines the cost-optimal mix of different power generation technologies within a power system. As an example, the long-term scenarios of the German government foresee only a minor contribution of solar photovoltaics in the future German power system. These scenarios are based on an analysis conducted about five years ago, when solar photovoltaics was certainly one of the more expensive renewable energy technologies, together with wind offshore and biomass. Recent cost developments, as well as expected future developments, indicate that in a cost-optimal power system, the role of solar photovoltaics should instead be similar to that of wind onshore, which is similarly cheap but

so far plays a much more prominent role in the scenarios. The same applies to a wide body of analysis and scenarios in various regions across the world.

A fundamental review of the future role and potential contribution of photovoltaics is also required for scenarios focusing not only on the power sector, but also on the heating and cooling and even the transport sectors, indicating that solar will play a major role in future global carbon-emission cost curves as well as regional decarbonization strategies in many parts of the world.

2   Motivation and scope of the study

Cost for power produced from solar photovoltaics (PV) in Germany has significantly decreased in the last years. The feed-in tariff paid for large scale PV systems declined from over 40 ct/kW in 2005 to below 9ct/kWh today (Figure 1). This massive reduction of about 80 percent in real terms exceeded expectations of policy makers and many industry experts. Solar PV, widely perceived to be a very expensive renewable energy technology, quite surprisingly turned into one of the cheapest forms of renewable energy in Germany.

Recent cost reductions are attributed to advancements in technology, production processes and industry development, but as well to government involvement in a global industry that is subject to significant international dispute. This has led to questions whether cost reductions observed

in Germany are sustainable or will reverse again in the future – and if and how the cost reduction of PV could continue. The reduced speed of cost reduction of PV systems in Germany over the last year has further increased divergence in opinions regarding this question.

For policy makers and decision makers in the energy industry the future development of the cost of PV is of high relevance. Both regulatory design and investment decisions require a long term perspective, as investments in the energy sector have a lifetime of several decades. The future cost of PV will determine the role of PV in the decarbonisation of the energy system – a question that may or may not need to be revisited in view of the developments of the last years.

Feed-in tariff for new large-scale solar photovoltaic in Germany   Figure 1
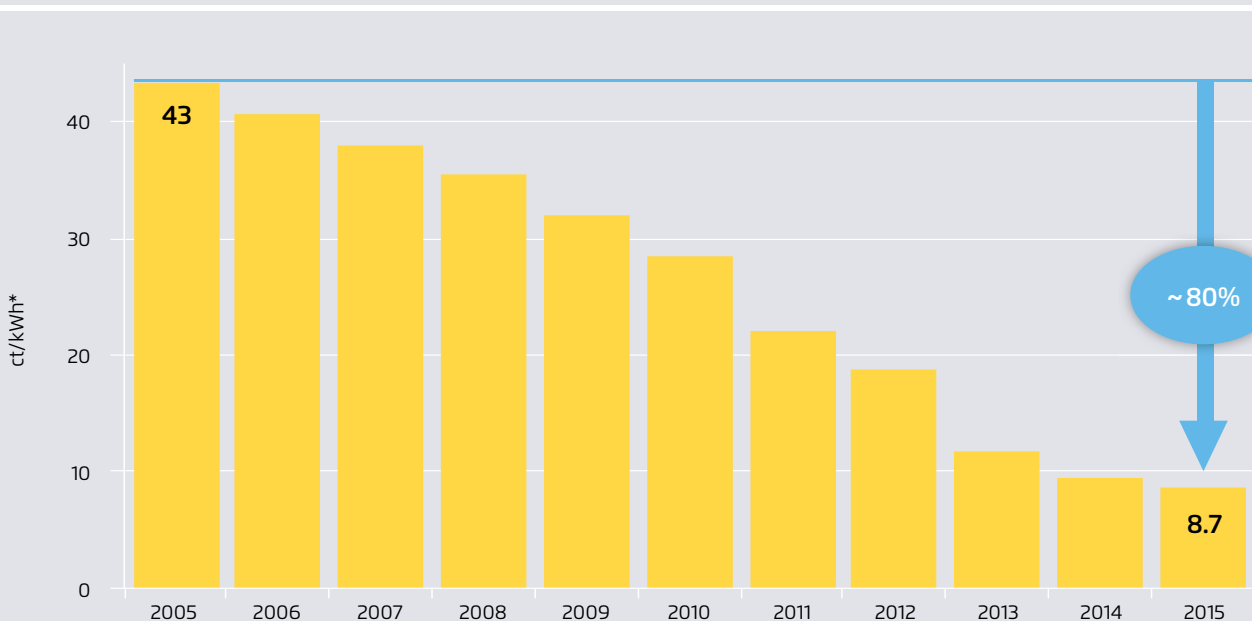
*Nominal values, Feed-in tariff applicable at first of January each year, value 2015 excl. adjustment of 0,4 ct/kWh for direct marketing

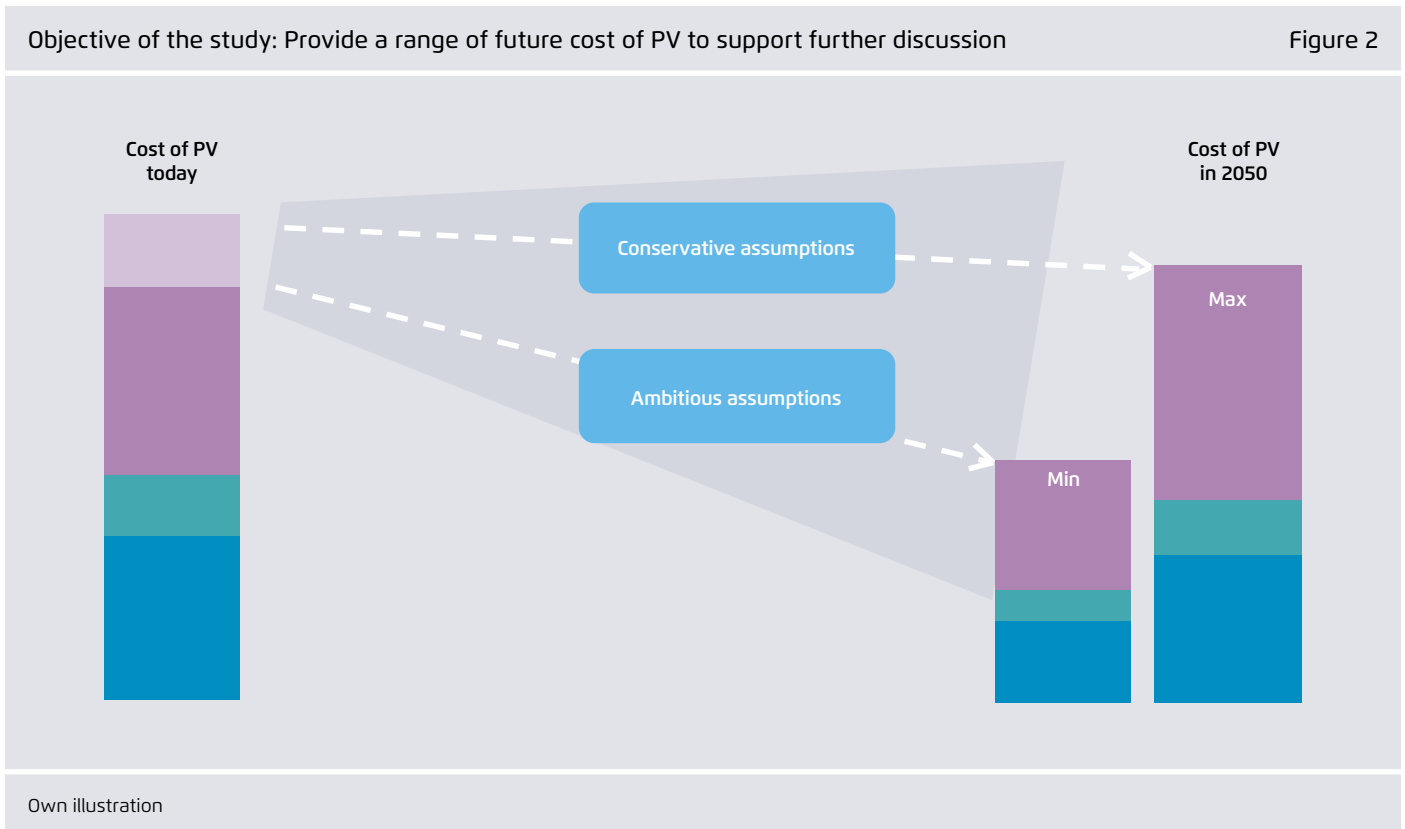German renewable energy law, Agora Energiewende

In order to support the further discussion on the role of PV, this study aims to analyse possible long-term developments of the cost of PV. This is achieved by identifying key assumptions that may or may not drive the cost reductions and developing scenarios that combine all best-case and all worst-case assumptions (Figure 2). As a reference year for long term scenarios, the year 2050 is chosen. This study thus aims to answer the question of what is the highest cost for solar PV that can be expected in 2050 as well as the question of what is the lowest cost that can be expected in 2050 with current technologies – both questions clearly being asked in the year 2014, with the full awareness that the scenarios in this study have to be reviewed in a couple of years to account for new technological achievements and to incorporate the actual market and price development of the PV industry.

Scope

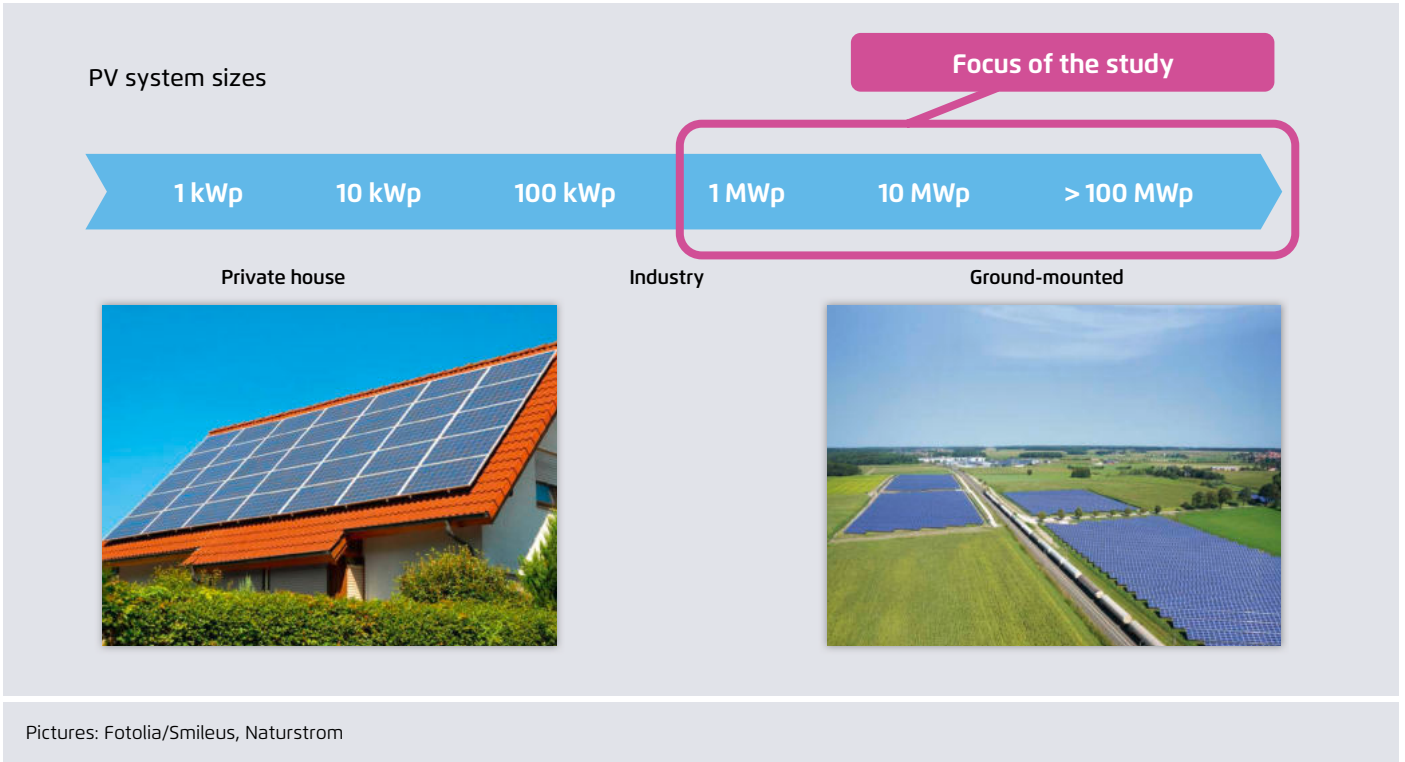An important restriction in this study is the focus on conventional silicon based solar technologies. This technology is only one of several ways to generate electricity by solar photovoltaics (Figure 4). Being the most widely deployed technology in terms of installed capacity, we use crystalline silicon technology as the conservative baseline to estimate future developments in cost. Possible technological breakthroughs in other solar photovoltaic technologies (e.g. organic solar cells) that might lead to lower cost than those of silicon technologies were not considered in this study. The cost scenarios in this study can therefore be considered as a conservative baseline of future cost for PV electricity. New solar cell technologies always have to compete with the cost of the existing crystalline silicon technology, so the costs have to be at the same level or lower in order to be successful on the market.

A second restriction in the scope of this study is the focus on ground-mounted systems. This focus was chosen because costs for ground-mounted systems are to a large part similar on an international scale, while cost drivers for small rooftop installations may differ more significantly from country to country.
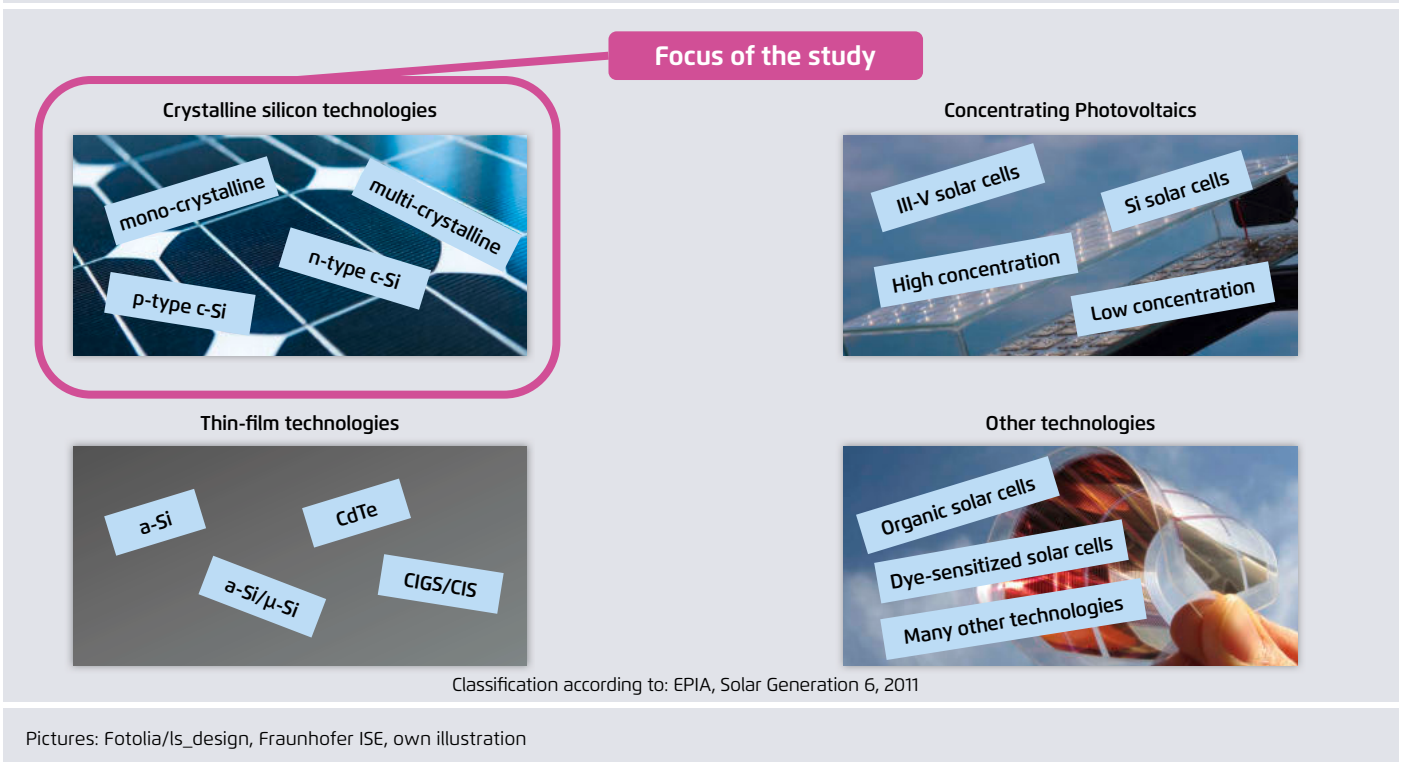

Objective of the study: Provide a range of future cost of PV to support further discussion   Figure 2

Own illustration

Scope: Focus on ground-mounted PV systems Figure 3

PV system sizes

Focus of the study

| 1 kWp | 10 kWp | 100 kWp | 1 MWp | 10 MWp | > 100 MWp |

Private house   Industry   Ground-mounted

Pictures: Fotolia/Smileus, Naturstrom

Focus on the most established module technology leads to a "conservative" estimate on future cost Figure 4

Focus of the study

Crystalline silicon technologies   Concentrating Photovoltaics

mono-crystalline
multi-crystalline
n-type c-Si
p-type c-Si

III-V solar cells
Si solar cells
High concentration
Low concentration

Thin-film technologies   Other technologies

a-Si
CdTe
a-Si/μ-Si
CIGS/CIS

Organic solar cells
Dye-sensitized solar cells
Many other technologies

Classification according to: EPIA, Solar Generation 6, 2011

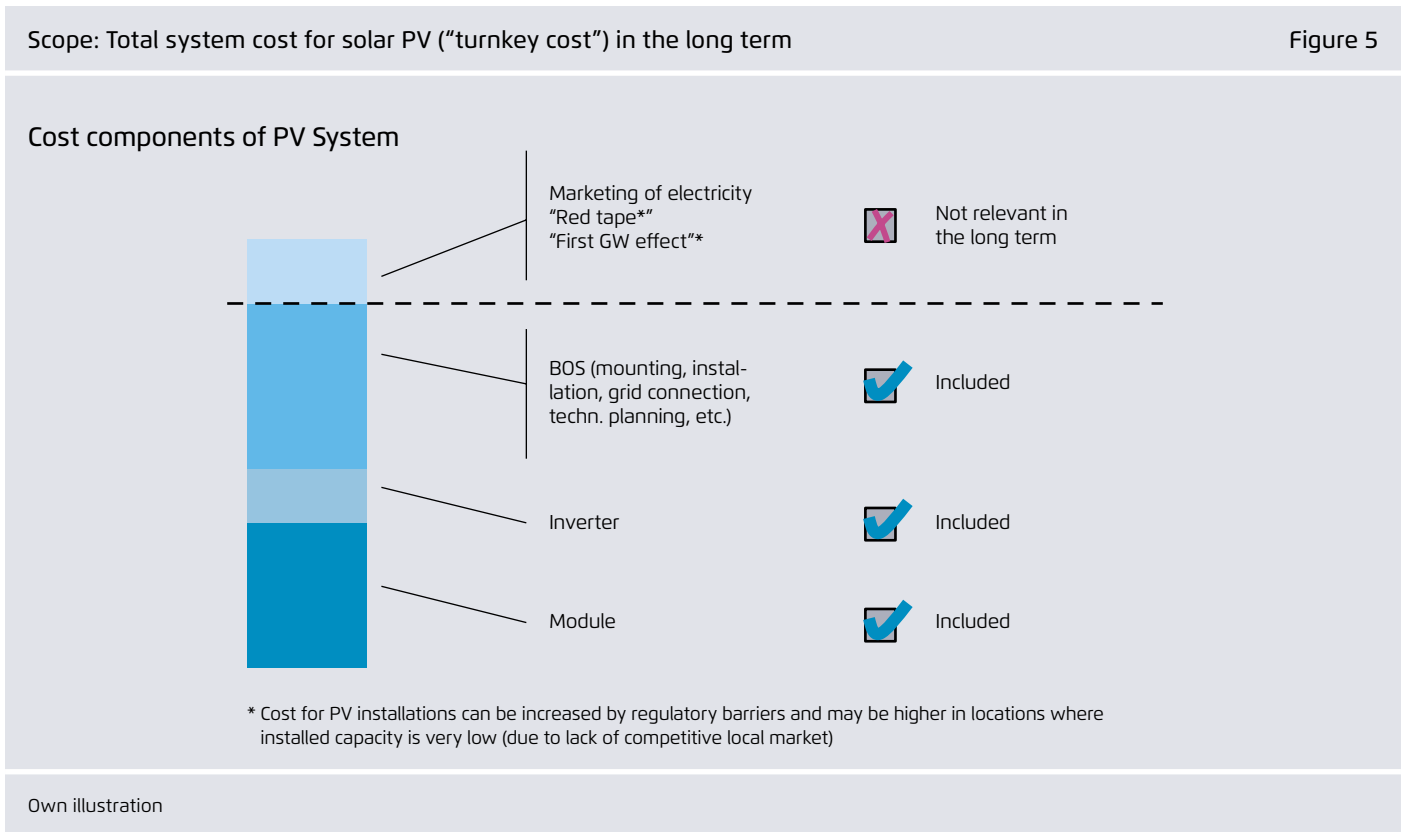Pictures: Fotolia/ls_design, Fraunhofer ISE, own illustration

The focus of this study is on the investment cost of solar PV power plants. "Cost" is understood here as "turnkey cost" of a power plant ready to be operated and connected to a distribution grid. This includes costs for modules and inverters as well as infrastructure development, planning and permits. Not included are all those costs that can be summarised under "red tape" or "first GW effect". If for example, permitting authorities are not enabled to issue permits or the lack of experience with connecting solar PV to a distribution grid poses significant challenge, this may lead to higher cost of a power plant. While such costs are relevant in certain less developed markets it appears safe to assume that such costs will not be relevant in the long term. To establish a baseline for the cost of PV today, the cost structure for ground-mounted solar farms built in Germany in 2013/2014 was used as a reference point, representing a comparatively well-developed market.

Approach

To develop possible scenarios of future cost of PV, this study applies a combination of literature analysis, expert interviews and expert estimations and builds strongly on the price experience curve approach for technology cost development. Using existing research at Fraunhofer ISE and expert interviews, a set of initial scenarios was developed and preliminary analysis conducted. These were discussed with a wide range of experts in three workshops that took place in Berlin, Brussels and Freiburg in May 2014 as well as in follow-up interviews. The workshops brought together experts from industry (including module equipment producers, module and inverter providers, project developers, power utilities and investors), researchers and policy makers. Based on the discussions at the workshop, the scenarios and cost assumptions were adapted and further analysis performed.

This study documents the results from the discussion and analysis which are clearly restricted by the time available for performing this study. It is important to emphasise that further research is needed that includes more detailed analysis of different solar PV technologies, differences in cost between different regions of the world and the influence of important cost drivers such as the cost of finance.

Scope: Total system cost for solar PV ("turnkey cost") in the long term	Figure 5

Cost components of PV System

Marketing of electricity
"Red tape*"
"First GW effect"*
❌ Not relevant in the long term

BOS (mounting, installation, grid connection, techn. planning, etc.)
✓ Included

Inverter
✓ Included

Module
✓ Included

* Cost for PV installations can be increased by regulatory barriers and may be higher in locations where installed capacity is very low (due to lack of competitive local market)

Own illustration

3   Scenarios for the future PV market development

3.1   Methodology explained: Scenarios for the PV market

In order to project the future cost development of photo-voltaic technology with a price experience curve later in the study, it is necessary to develop scenarios for the global PV market first. A two-step approach is used in this study (Figure 6): First, a bottom-up approach is applied to develop scenarios for market development based on different annual growth rates until 2050. In a second step, a top-down feasi-bility check is performed by calculating the resulting share of PV in the global electricity generation in 2050. Based on this feasibility check and the expert discussions, a range of long term market development scenarios was selected for the further analysis.

To depict a more realistic long-term market development, an S-curve model for technology diffusion was then applied to detail the yearly expansion of installed capacity.

The S-curve approach for PV market development
Assuming a continuous yearly market growth by a fixed percentage would result in an exponential market growth where most of the capacity is added in the last few years before 2050. In real markets such exponential market de-velopments may occur over a limited time but do not persist over longer periods of time including several decades. The S-curve concept is an approach to describe the diffu-sion process of a technology into the market [3].

"Bottom-up" approach is used to estimate the long-term market development of PV until 2050, followed by a "top-down" crosscheck with electricity demand in 2050

Figure 6
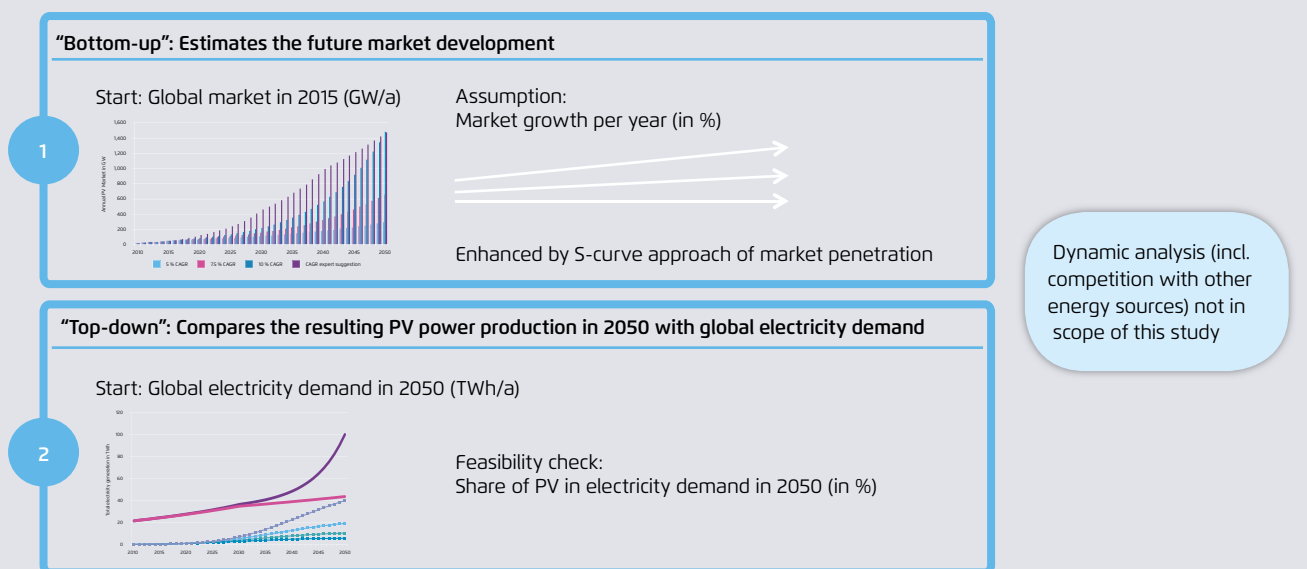
Own illustration

The time-dependent dynamic of technology market penetration is described by a logistic growth function:

$$f'(t) = k \cdot f(t) \cdot (S - f(t))$$

(t):   quantity at time t
$f'(t)$:   rate of change at time t
k: factor of growth
t: point in time
S: saturation limit of (t)

The logistic growth function can be solved by the logistic function; the solution is an S-shaped curve:

$$f(\text{t}) = \frac{f(0)}{f(0) + (S - f(0)) \cdot e^{-Skt}}$$

with $f(0)$: quantity at time $t = 0$

This study defines the saturation limit S as the production capacity of PV systems of the PV industry (i.e. the PV market) in 2050. Hence, (t) denominates the annual production of PV systems and $f'(t)$ the change in production capacity of PV systems, i.e. the growth of the annual PV market.

In scenario S, the size of PV system production capacity varies. Considering the growing need for repowering of existing PV systems, the share of the PV repowering market converges to the total annual PV market in the long term (after 2050).

Another approach of defining the saturation limit S as the total installed PV capacity was tested. This resulted in a "camel hump" shaped curve of the annual market, reaching the first market maximum around 2025 and the second close to 2050 with a significant market decline between those maxima. This behaviour can be explained with the need of repowering, which basically repeats the historical market development with a delay of the system lifetime. Such a market development obviously does not occur in reality. We therefore decided to not apply this alternative approach but to apply the S-curve to annual production capacity as described above.

3.2 Historical market development and short-term outlook

In the last decade the global PV market developed very fast, multiplying the installed capacity by a factor of 15 in just six years and reaching 139 GW by the end of 2013, which is illustrated in Figure 7.

Before developing scenarios for the future, we analysed the historical situation and short-term market projections until 2018 and 2020, depicted in Figure 8. The historical data is based on the EPIA Global Market Outlook for Photovoltaics [4] and result in a compound annual growth rate (CAGR) of 50 percent between 2000 and 2013. The projections for the near future depicted in Figure 8 are results of different market research institutions as well as contributions by experts at the workshops. The projections until 2015 expect a CAGR of approximately 20 percent; until 2020 a reduced CAGR of 17 percent or below is expected.

For our long-term market scenarios we take the average of the different short-term forecasts for 2014 and 2015, which is 45.2 GW and 52.7 GW respectively, as a starting point. The variation of the annual market starts in the year 2016.

## 3.3 Scenarios for the global electricity consumption

In order to calculate the PV share in the global electricity mix resulting from the different bottom-up market scenarios, it is necessary to make projections on the global electricity generation until 2050.

The first projection is based on scenarios that were developed by the International Energy Agency (IEA) for the Energy Technology Perspectives 2014 report [5]. We take the average of the 2DS and 4DS scenarios, which results in a global electricity generation of approx. 43,600 TWh in 2050 (from 23,700 TWh in 2014).

At the expert workshops, several experts stressed the relevance of the increasing trend of electrification in the transport, building and industry sectors as a key measure

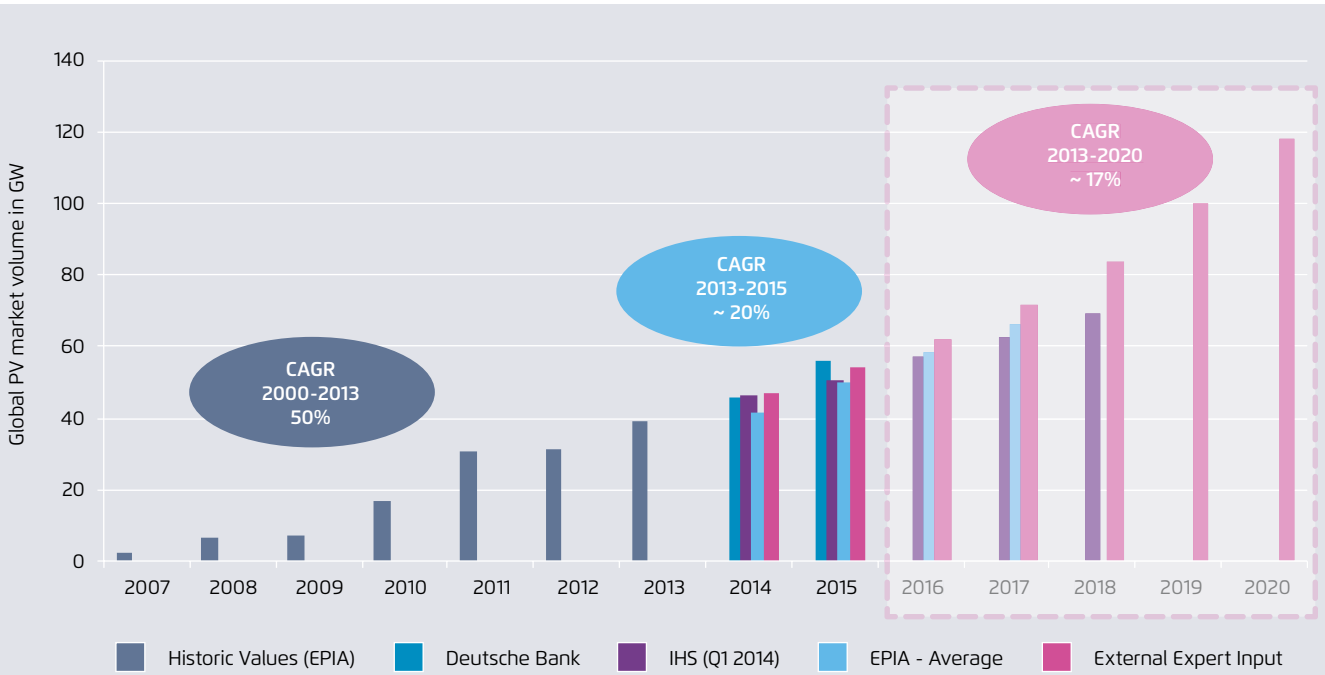## Historical development of installed PV capacity worldwide   Figure 7

Increase of installed power by a factor of 15 within six years
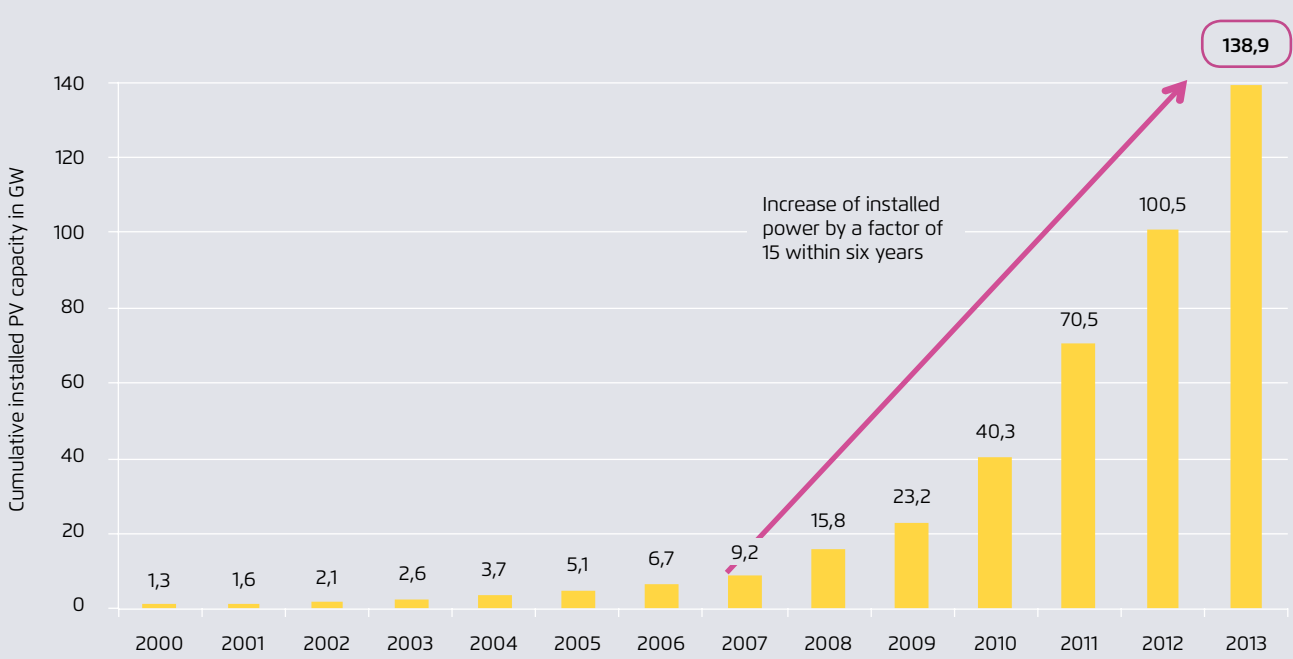
Own illustration based on data by EPIA [4]

Short-term market estimations for 2015 are used as starting point for scenario estimations   Figure 8

CAGR 2000-2013 50%

CAGR 2013-2015 ~ 20%

CAGR 2013-2020 ~ 17%

Legend: Historic Values (EPIA) · Deutsche Bank · IHS (Q1 2014) · EPIA - Average · External Expert Input

Expert workshops

to replace fossil fuels by renewable energy. We therefore consider a second scenario ("high electrification") that accounts for this effect and which was suggested by Professor Christian Breyer of Lappeenranta University in Finland. The "high electrification" scenario is also building on figures from the International Energy Agency: it incorporates the 2DS and 4DS scenarios as a baseline for electricity demand until 2050. Furthermore it assumes that 50 percent of the projected fossil energy demand (IEA, World Energy Outlook 2013, [6]) will be replaced by electric power, which is added to the baseline scenario as additional electricity demand. The shift from fossil fuels to electricity from renewable energies induces efficiency gains in terms of primary energy demand, which are expected to be high in the transport sector, low in the building sector and unclear in the industry sector at this time. An overall 20 percent efficiency gain is therefore assumed in the scenario by shifting from fossil to renewable power. The "high electrification" scenario results in approx. 100,000 TWh of global electricity generation in 2050. Both scenarios are shown in Figure 9.

3.4 PV market scenarios

A combination of bottom-up and top-down approaches was applied to develop a set of scenarios that was discussed and refined at the expert workshops (Section 3.1). The four scenarios selected for further analysis in this study are described in the following, including some insights of the discussion at the expert workshops.

The most **pessimistic scenario** (scenario 1) considered in this study is based on a 5 percent CAGR of the global PV market after 2015. More pessimistic scenarios, e.g. assuming no further market growth or even a reduction in market volumes in the long term, were discussed with experts but widely dismissed as not realistic. An **intermediate scenario** (scenario 2) builds on a 7.5 percent CAGR and an **optimistic scenario** (scenario 3) on a 10 percent CAGR (scenario 3) between 2015 and 2050. Based on the discussion in the expert workshops, an additional **PV breakthrough scenario** (scenario 4) was developed to assess the impact of an "extreme" market scenario. This scenario is not based on a bottom-up

Electricity demand in 2050 highly depends on electrification of the energy sector – IEA scenarios are used; additionally a scenario by Professor Breyer is considered

Figure 9
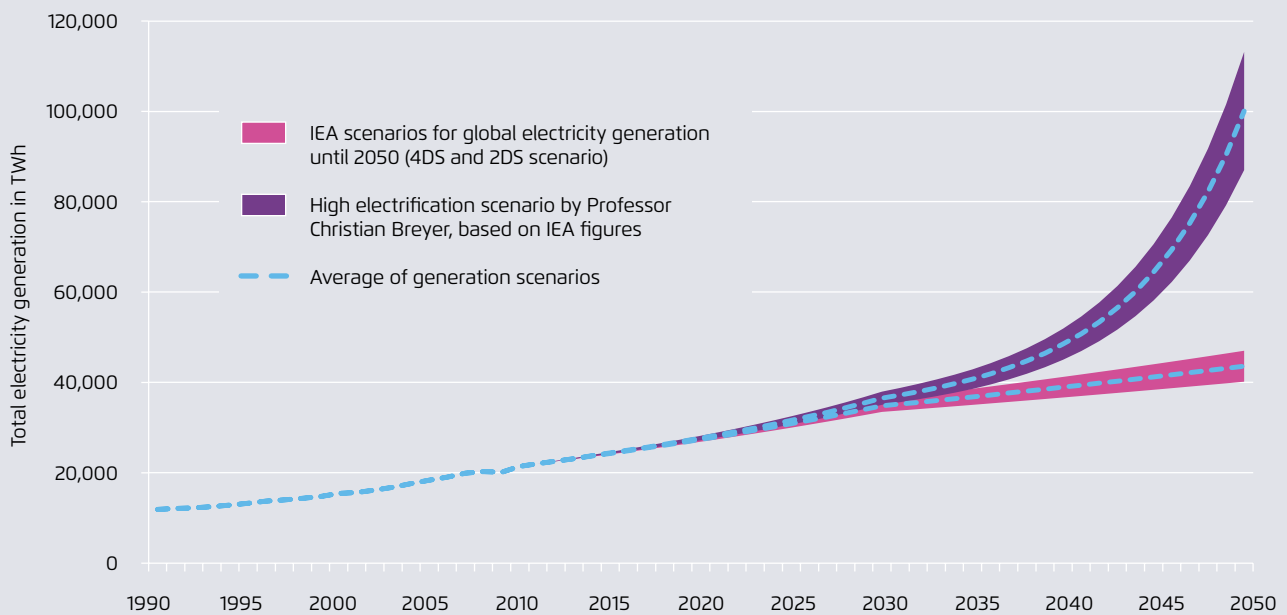
Own illustration, data from IEA [5] [6]

assumption on market growth but rather takes as a starting point a largely PV-based energy system in 2050, in which PV provides 40 percent of global electricity demand in a "high electrification" scenario.

The range of annual PV market growth in the three key scenarios considered is with 5-10 percent considerably lower than the historical growth of 50 percent (CAGR 2000-2013). This is due to the fact that a very high growth rate mostly occurs in relatively young markets, but is unlikely to sustain over a longer period of time.

The development of the PV market based on the assumptions on annual growth in scenarios 1 to 3 is illustrated in Figure 10. At the expert workshop, an additional scenario was suggested that assumes a CAGR of ~20 percent until 2020, ~14 percent in the period of 2020 to 2030, ~8 percent from 2030 to 2040 and ~4 percent from 2040 to 2050. This scenario was considered as most realistic by most attending industry experts. As described below, the S-curve approach applied to the bottom-up scenarios considered leads to a

more realistic form of market penetration that resembles this pattern. As scenario 3 (optimistic scenario) largely coincides with the expert scenario suggestion, it has not been separately included in the analysis.

The resulting cumulative produced PV capacities from 2015 to 2050 and the installed capacities in 2050 are summarised in Table 1. To calculate the installed capacity in 2050, the decommissioning of old PV plants is considered to take place after 25 years lifetime. For new plants built after 2025, longer lifetimes appear to be appropriate due to technological improvements; but they are not relevant for this specific calculation. For the calculation of the levelised costs of electricity (LCOE) for PV systems in 2050, a system lifetime of 30 years is assumed.

Three long-term scenarios are developed using assumptions on yearly market growth rates from 5% to 10% per year after 2015   Figure 10
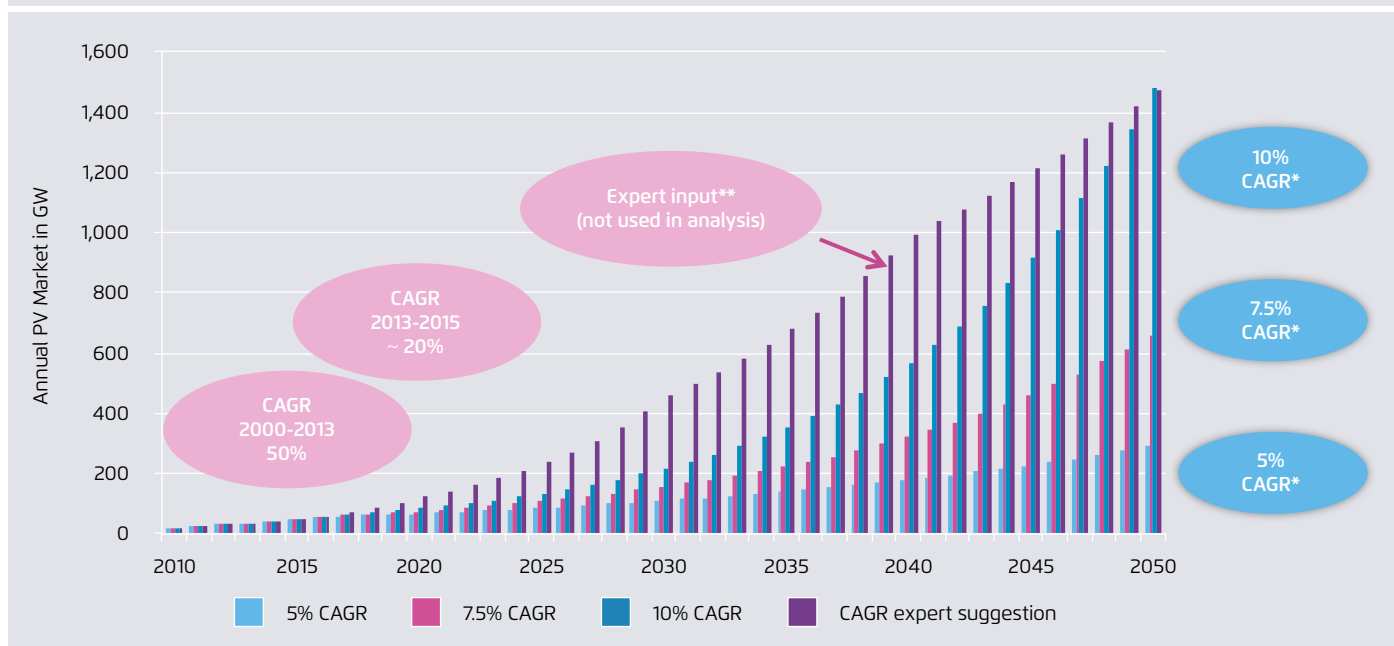
Own illustration   * CAGR = Compound Annual Growth Rate; ** Suggested market growth by year: 2014-2020: ~20%; 2020-2030: 14%; 2030-2040: 8%; 2040-2050: 4%; Considered by applying the S-curve approach to all scenarios

Installed and produced PV capacity until 2050 (rounded values)   Table 1

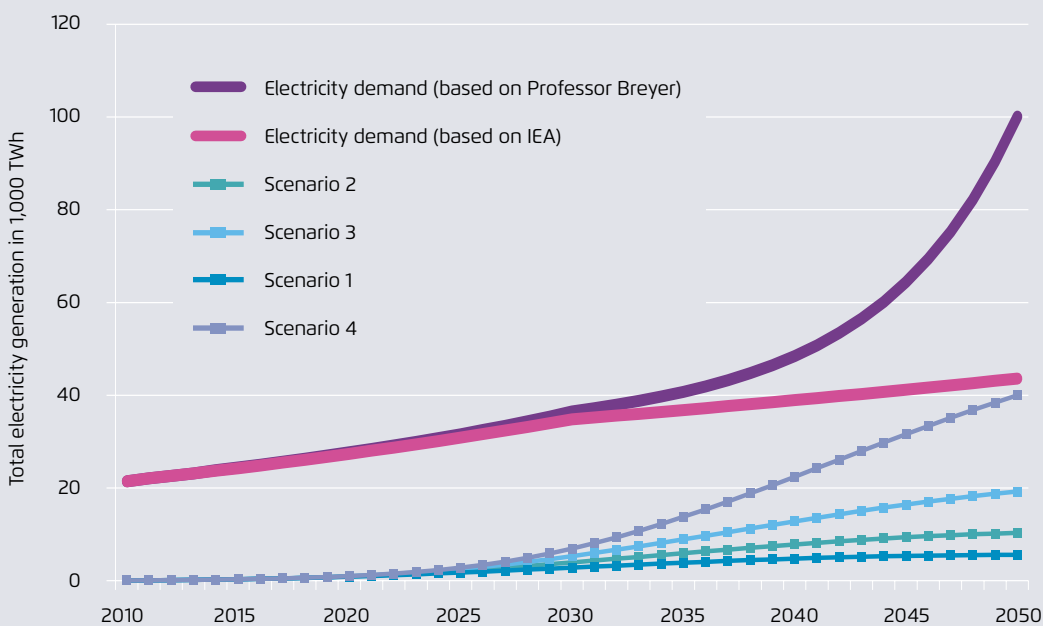| Scenario	5% CAGR	7.5% CAGR	10% CAGR
Installed in 2050	4,300 GW	7,900 GW	14,800 GW
Cum. production	5,600 GW	9,600 GW	16,700 GW

Own calculation

tilted PV systems (without tracking) of 1690, 1780 and 1850 kWh/m²/yr with the weighting factor being today's electricity generation, land area and population respectively [7]. Assuming an average performance ratio of 80 percent, this would translate in an annual electricity production of 1352, 1424 and 1480 kWh/kWp respectively. With tracking systems applied to a certain share of installations, the average electricity is further increased, whereas east-west-facing systems would potentially decrease the average production. Considering all these factors, our assumption of 1300 kWh/kWp seems to be a fairly reasonable, conservative estimate.

To calculate the PV electricity production from the total installed capacity, a global annual average production of 1300 kWh per installed kWp of PV electricity is assumed in this study. While this figure is subject to a large uncertainty due to the future distribution of PV systems and the local irradiation conditions as well as the amount of east-west-facing systems, it was generally supported in the workshops as a conservative basis to estimate the electricity yield of PV on a global scale. Another study mentioned at the workshop has calculated a weighted global average irradiation on fixed

The resulting scenarios of global electricity production of PV and the scenarios of global electricity demand (Section 3.3) are summarised in Figure 11. The shares of PV in the electricity demand in 2050 for each of the four PV market scenarios that were the basis for the feasibility check are depicted on the right-hand side of Figure 11.

Based on the IEA projection for the global electricity generation, scenario 1 (5 percent CAGR) results in a 13 per-

Crosscheck of the scenarios with global electricity generation: PV breakthrough scenario only feasible with electrification   Figure 11

Own illustration

cent PV market share. Scenario 2 (7.5 percent CAGR) leads to a 24 percent PV market share and scenario 3 (10 percent CAGR) results in a 44 percent market share. Based on the higher electricity generation scenario by Professor Breyer, the PV shares are lower, at 6, 10 and 19 percent respectively.

The feasibility check performed in this study was based on expert judgement and discussion. The resulting shares of up to 18 percent PV contribution to electricity demand in 2050 were widely acknowledged as being feasible without doubt from an electricity system point of view. It was pointed out that already today a number of regions in Italy show penetration rates of close to 10 percent. The resulting share of 44 percent in scenario 3 combined with a global electricity generation according to the IEA scenario was considered as feasible, but was discussed controversially at the workshops. A stronger electrification of the energy system (electricity demand scenario by Professor Breyer) would reduce the share of PV in this scenario to 19 percent, emphasising the importance of the assumptions on the entire energy system in evaluations on future PV market scenarios.

The PV breakthrough scenario (scenario 4) is clearly not feasible in case of an electricity demand development according to the IEA scenarios, as an electricity system based on 92 percent appears technically not realistic, given the seasonal variations of solar irradiations. This market development scenario rather depends on a significant electrification of the energy sector. In such a case, the 40 percent PV share in electricity was considered as technically more feasible than in the non-electrified scenario, as new electricity consumers such as electric vehicles would imply a significant increase in flexible demand.

A further scenario building on a long term CAGR of 15 percent has been excluded from further analysis as the resulting share of 67 percent PV of electricity demand – even in the case of high electricity demand – was not considered as technically feasible.

Using the total installed PV capacity in 2050 of the 4 scenarios as a starting point, a more realistic market penetration path was developed for each scenario. The S-curve

Market development scenarios are adjusted with S-curve approach to represent typical market penetration   Figure 12
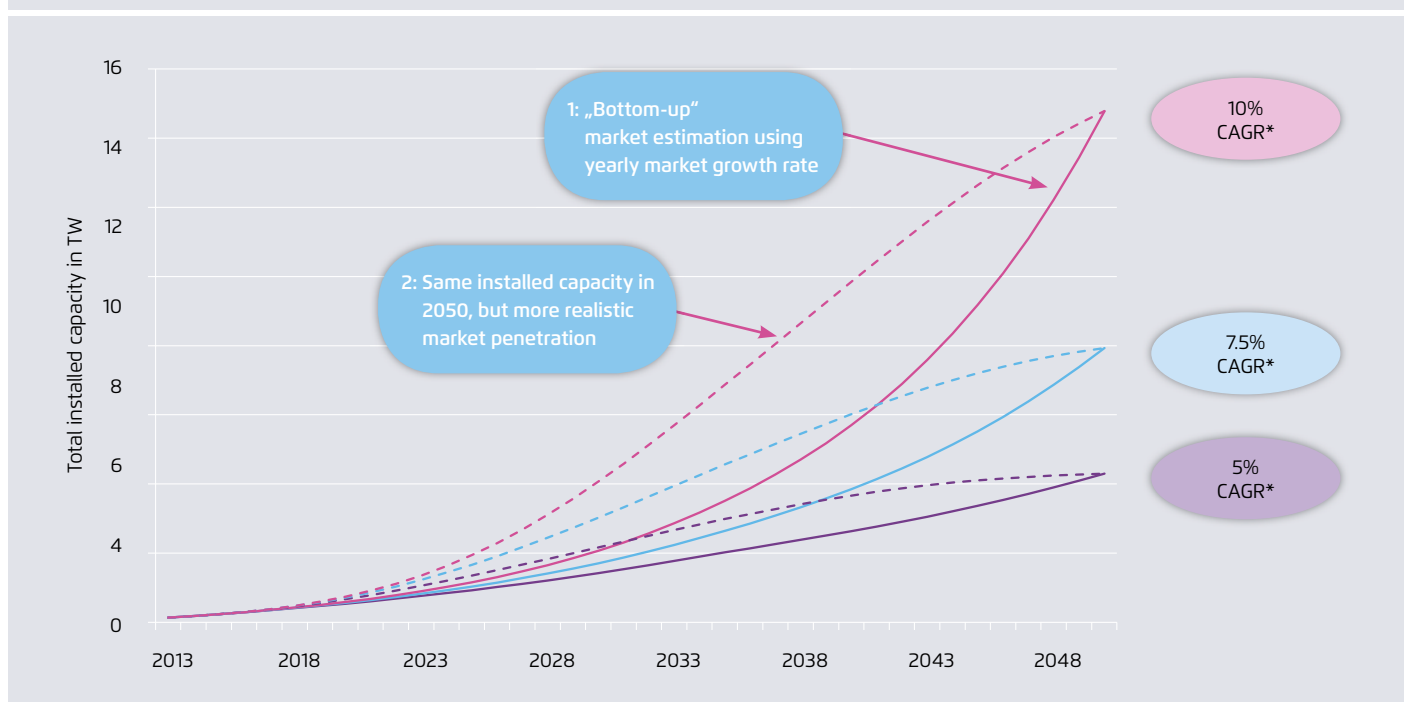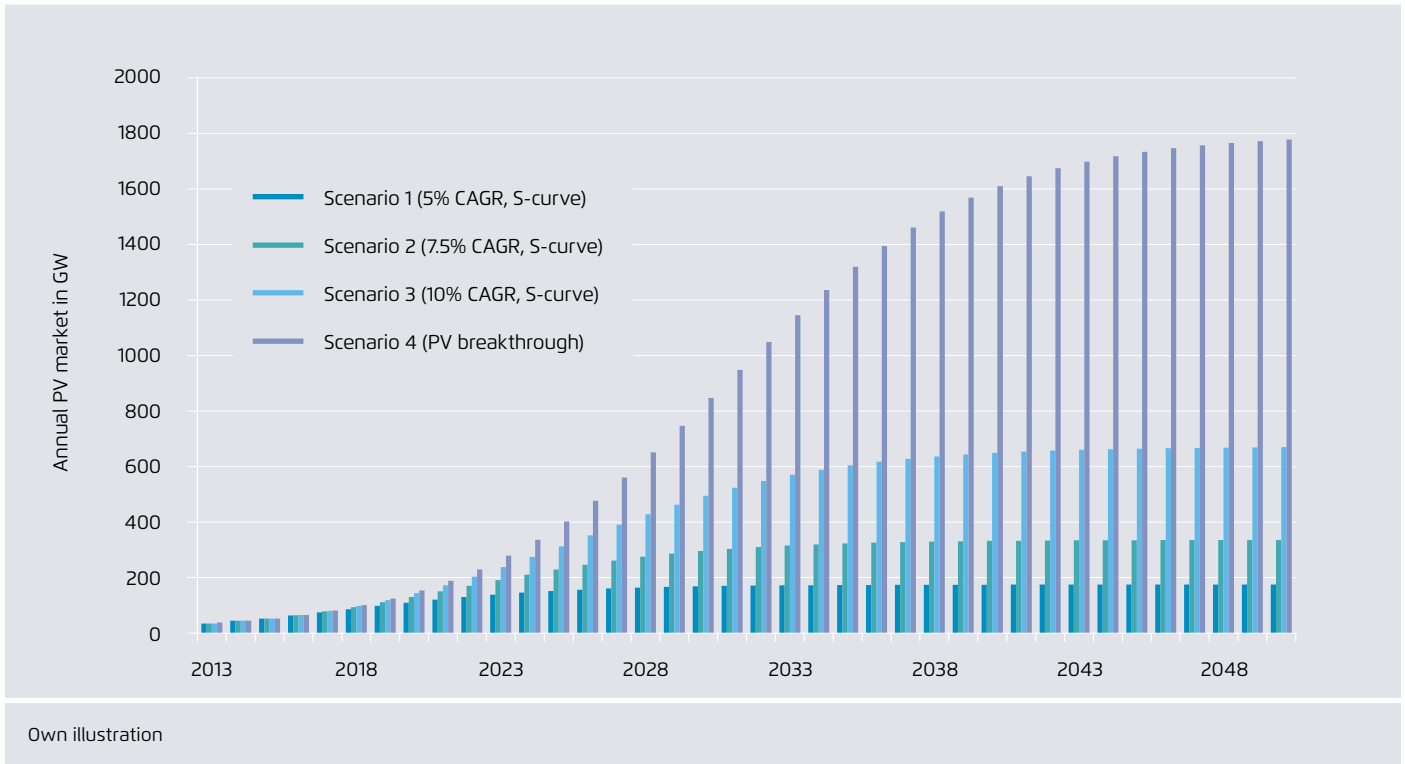
Own illustration

Projection of the annual global PV market development in 4 different scenarios Figure 13

Own illustration

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method as described in Section 3.1 was applied to define the annual production curve, which results in the path for the installed capacity..Figure 12 illustrates this approach for scenarios 1 to 3. The detailed S-curves for the different scenarios are presented in the appendix in Section 8.1.

Figure 13 shows the resulting annual PV market development for the 3 scenarios as well as the PV breakthrough scenario, representing the more realistic S-curve shape of market developments. Scenario 1 results in an annual PV market of 200 GW in 2050, scenario 2 in 400 GW, scenario 3 in 850 and the PV breakthrough scenario in 1,800 GW of gross annual PV capacity additions. Note that the annual net added PV capacity is lower due to the replacement of old systems at the end of their lifetime.

In order to test the results of the modelled S-curve scenarios for the near future, we compare them with the short-term market forecast until 2020 described in Section 3.2. The average of the different annual PV market forecasts is plotted in Figure 14 together with the modelled S-curve scenarios.

The market for 2014 and 2015 was fixed in the modelling process as described in Section 3.2. Scenario 1 fits very well with the expert forecast; scenario 2 is only slightly higher with an annual market development of approx. 130 GW in 2020, compared to 120 GW in the expert forecast. The market figures in the PV breakthrough scenario are about 30 GW larger than the average of the short-term market forecast. It is important to note that if the actual short-term market development differs from a scenario, this does not mean that this scenario is unrealistic in the medium and long term. Real market developments are always subject to fluctuations that are not reflected in the S-curve approach. To determine which scenario is the most realistic in the medium and long term, we will have to recheck the figures of this study in a couple of years. Table 2 gives an overview over the PV market scenarios we have developed using the S-curve approach.

| Characterisation of the S-curve scenarios (values for 2050)				Table 2
Values for 2050	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Market size [GW/a]	175 GW	336 GW	670 GW	1,583 GW
Installed capacity [GW]	4,295 GW	7,931 GW	14,778 GW	30,749 GW
Annual electricity generation [TWh/a]	5,584 TWh	10,310 TWh	19,212 TWh	39,974 TWh
Total produced Capacity [GW]	5,649 GW	9.597 GW	16,721 GW	32,925 GW
Total repowered capacity [GW]	1,354 GW	1.666 GW	1,942 GW	2,174 GW

Own calculation

The key parameter to determine the future cost of components of PV systems by a learning approach (methodology of price experience curve described in Section 4.1) is the number of duplications in the cumulated produced PV capacity until 2050. We calculated the corresponding duplications for each of the 4 scenarios (Figure 15). Starting today, the total amount of PV systems produced would be duplicated between 5.4 and 7.9 times in the four scenarios considered.

At first sight, the relatively small difference of the number of duplications between breakthrough scenario 4 and the other scenarios appears to be surprising in view of the large differences in assumptions on global electricity demand and
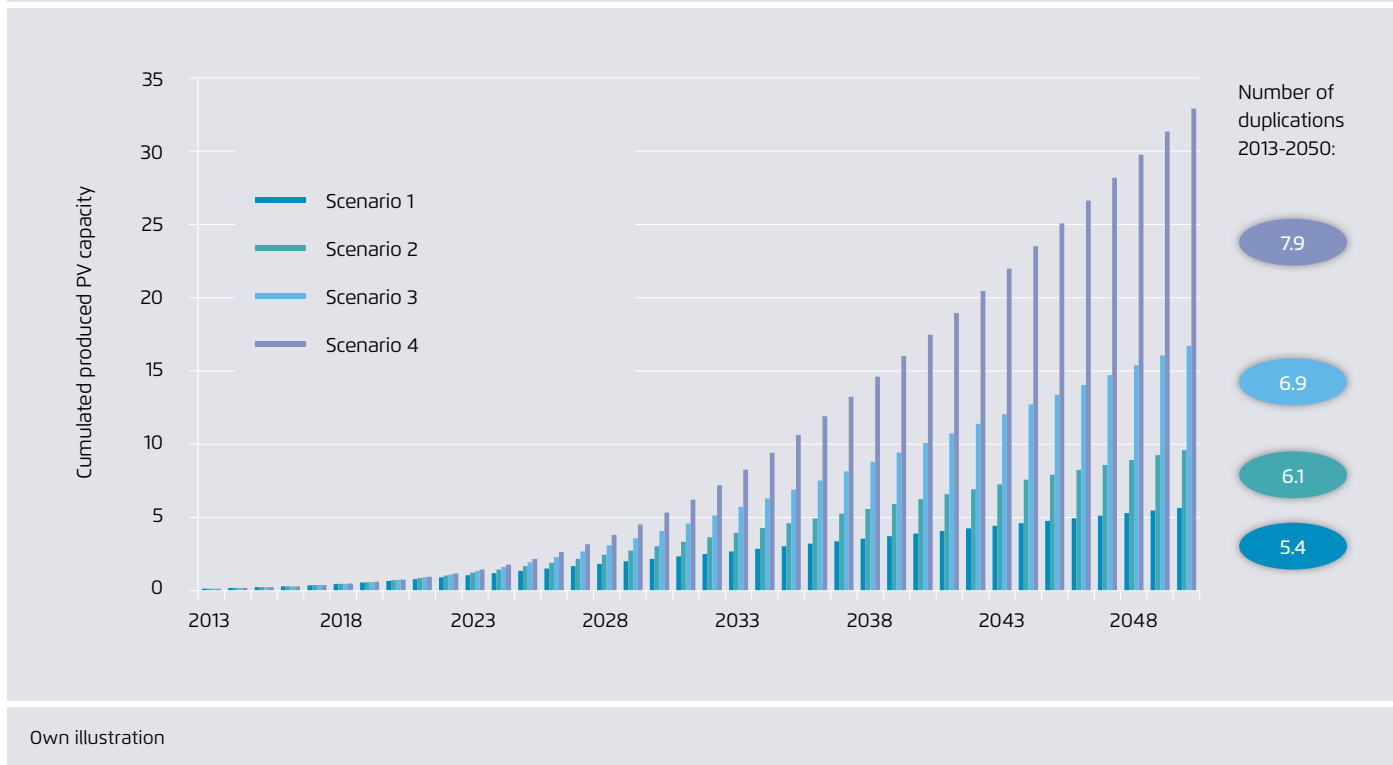
Plausibility check of the S-curve scenarios with the short-term market outlook — Figure 14
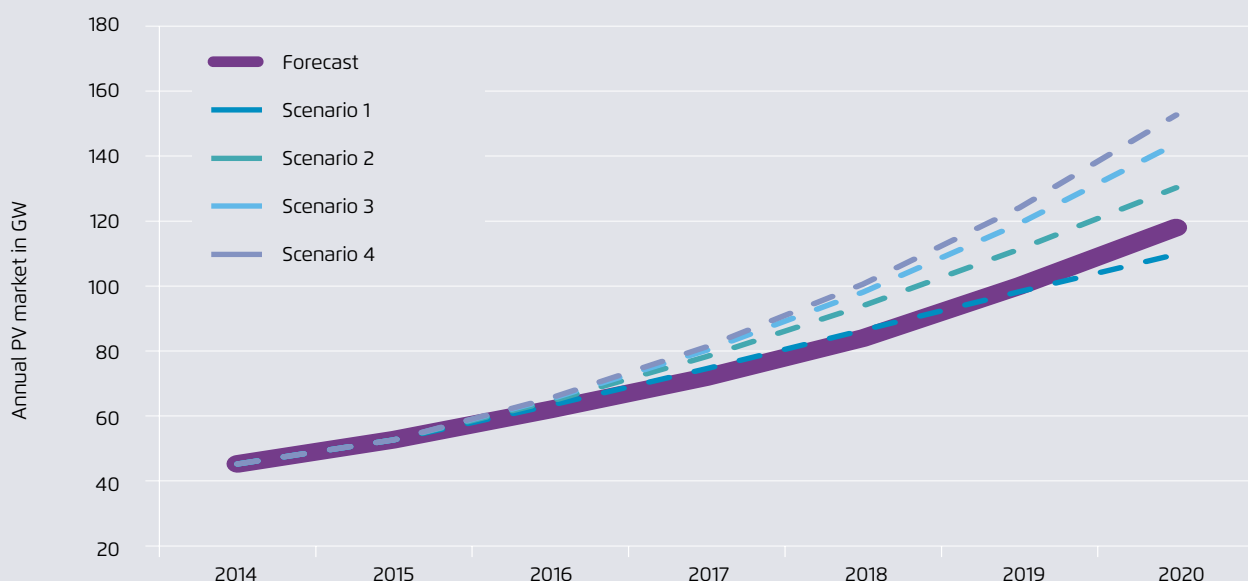
Own illustration

| Projection of the cumulated produced PV capacity and the number of remaining duplications in the scenarios | Figure 15 |

Own illustration

the PV share in electricity generation in the different sce-
narios. But if you take a closer look, this is yet less surpris-
ing, as one duplication of cumulative capacity quite natu-
rally leads to roughly a duplication of e.g. the share in the
electricity demand.

4. Price-experience curve of PV modules and inverters

4.1 Methodology explained: The price experience curve

The cost and price dynamics of technologies are often quantified following the experience curve approach, which relates the cumulative produced quantities of a product and the sinking unit costs (production costs). The concept is based on learning effects, which were first described by Wright as early as 1936 in a mathematical model for production costs of airplanes [8]. It was later generalised by Henderson of the Boston Consulting Group (BCG) to the price development of a globally traded product [9] [10]. The central empirical observation is that the costs (price) of a specific product changes (most often decreases) by an individual percentage-number (price experience factor) every time the cumulative produced volume doubles. Mathematically this is expressed by (e.g. [11])

$$C(x_t) = C(x_0) \left(\frac{x_t}{x_0}\right)^{-b}$$

with the cumulated production xt and cost (or price) C(xt) at time t in relation to the corresponding values x0 and C(x0) at an arbitrary starting point. The central parameter b is called learning parameter. Applying the logarithmic function to equation (1) allows plotting a linear experience curve with b as the slope parameter. Note that price experience curve usually refers to the price of a product, whereas the term learning curve is used when the concept is applied on cost. The main outcome of this analysis is usually the learning rate (LR) or the progress ratio (PR), which is defined as (e.g. [11])

$$LR = 1 - 2^b = 1 - PR$$

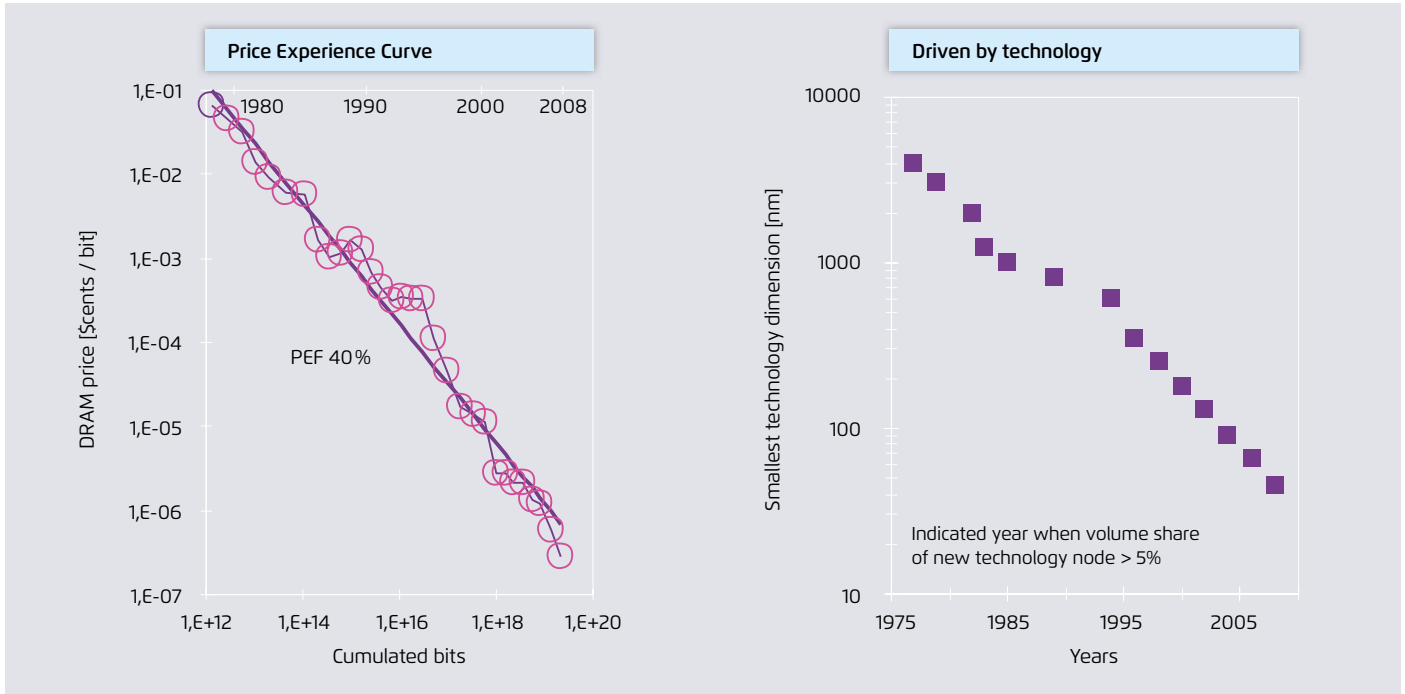Methodology explanation: The price experience curve   Figure 16
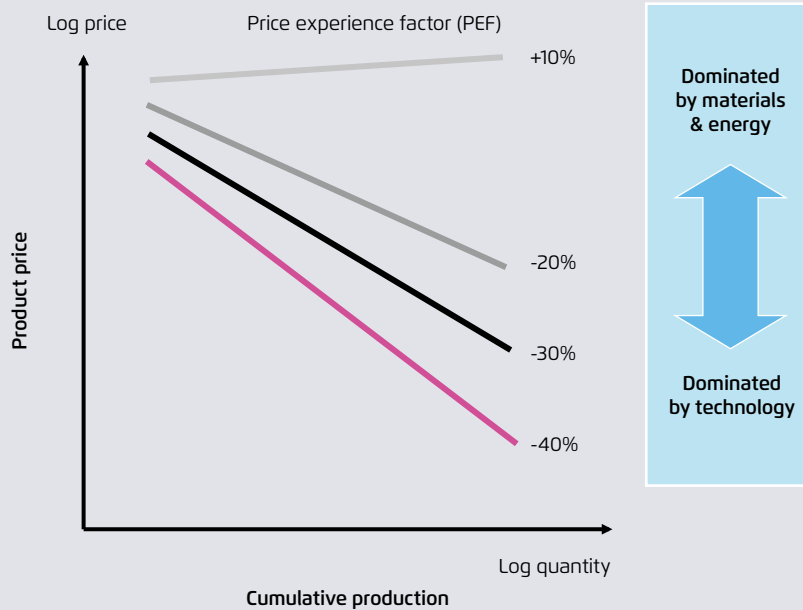
Own illustration based on Winfried Hoffmann [14]

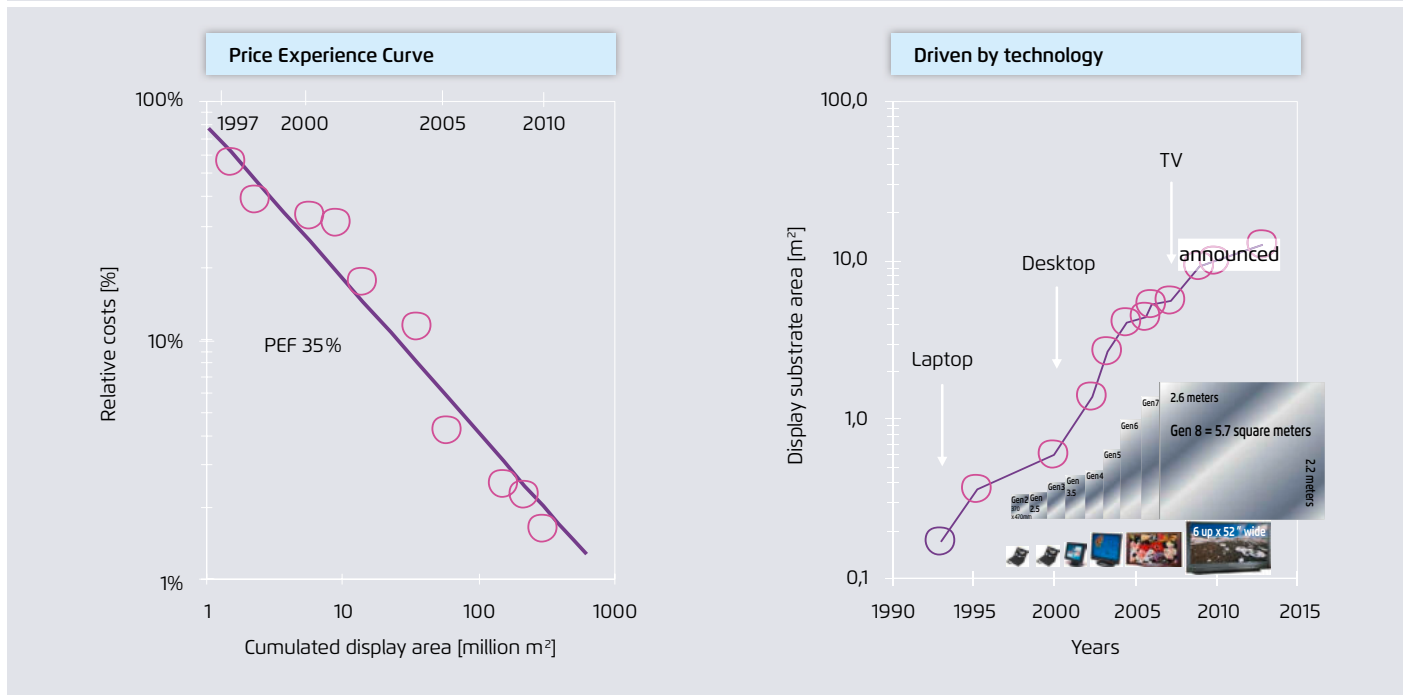Example for price experience factors from other industries: DRAM technology   Figure 17

Price Experience Curve

PEF 40%

DRAM price [Scents / bit] — 1,E-01, 1,E-02, 1,E-03, 1,E-04, 1,E-05, 1,E-06, 1,E-07

Cumulated bits — 1,E+12, 1,E+14, 1,E+16, 1,E+18, 1,E+20

1980 1990 2000 2008

Driven by technology

Smallest technology dimension [nm] — 10000, 1000, 100, 10

Indicated year when volume share of new technology node > 5%

Years — 1975, 1985, 1995, 2005

Winfried Hoffmann [14]

Example for price experience factors from other industries: Flat screen displays   Figure 18

Price Experience Curve

PEF 35%

Relative costs [%] — 100%, 10%, 1%

Cumulated display area [million m²] — 1, 10, 100, 1000

1997 2000 2005 2010

Driven by technology

Display substrate area [m²] — 100,0, 10,0, 1,0, 0,1

TV
announced
Desktop
Laptop
2.6 meters
Gen 8 = 5.7 square meters
2.2 meters
Gen2 Gen 2.5 Gen3 Gen 3.5 Gen4 Gen5 Gen6 Gen7
6 up x 52 " wide

Years — 1990, 1995, 2000, 2005, 2010, 2015

Winfried Hoffmann [14]

For example, if the cumulated produced volume doubles and the costs (price) sink by 20 percent, one speaks of a learning rate of 20 percent (or a progress ratio of 80 percent), see Figure 16. If applied to the price of a product, the learning rate is often called price experience factor (PEF).

Although the approach might at first seem incidental, it has already been validated for various products, in particular for energy supply and demand technologies, e.g. [12] [13].

4.2 Price-experience curve of PV modules

The price dynamics of PV modules have followed a price experience curve since 1980 (Figure 19). Several oscillations below and above the trend line are observable. Such price behaviour is not uncommon and has been observed for various technologies. PV module oscillations above the learning curve were for example caused by material scarcity and scarcity in production facilities along different parts of the module production value chain. An extensive discussion of the experience curve for PV can for example be found in Ref. [11].

It is important to note that the learning rate depends on the time period, which is used for fitting the trendline. The starting year for PV module experience curves is 1980 in our analysis. Figure 20 shows learning rates depending on the date until which the data is fitted. The values vary from 19.8 to 22.6 percent, leading to an average learning rate of 20.9 percent, which is in line with established literature [15].

In order to use the price experience curve for an estimation of long-term cost development of PV modules, two questions need to be answered and were discussed intensively at the expert workshops:

→ 1. Will the historical price development, according to the learning rate curve (red line in Figure 21), continue in the future and if so, at what rate?
→ 2. Will the current deviation from the historical learning rate (year 2013 and 2014 are significantly below the red line in Figure 21) return to the historical learning curve, and if so, by what date?

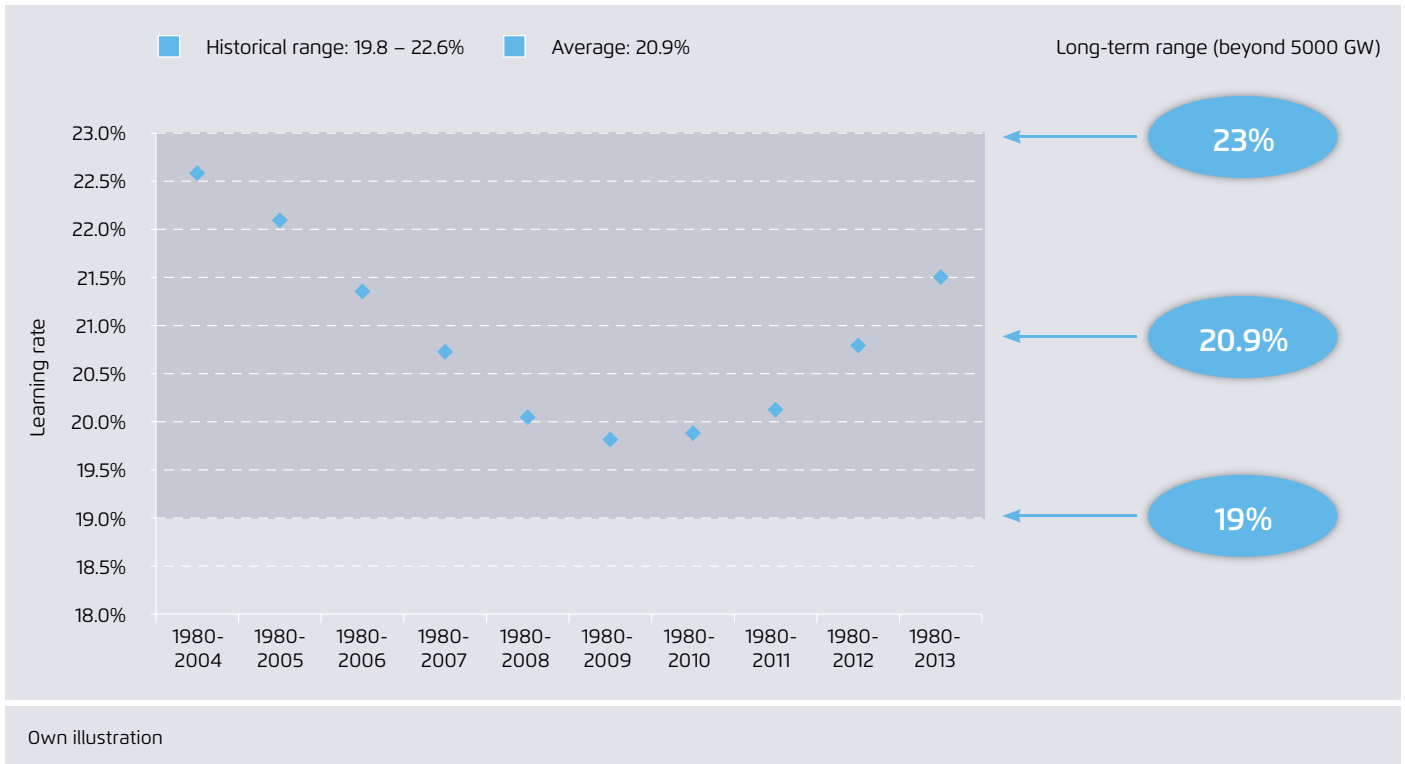**Historical price experience curve of PV modules since 1980**   Figure 19
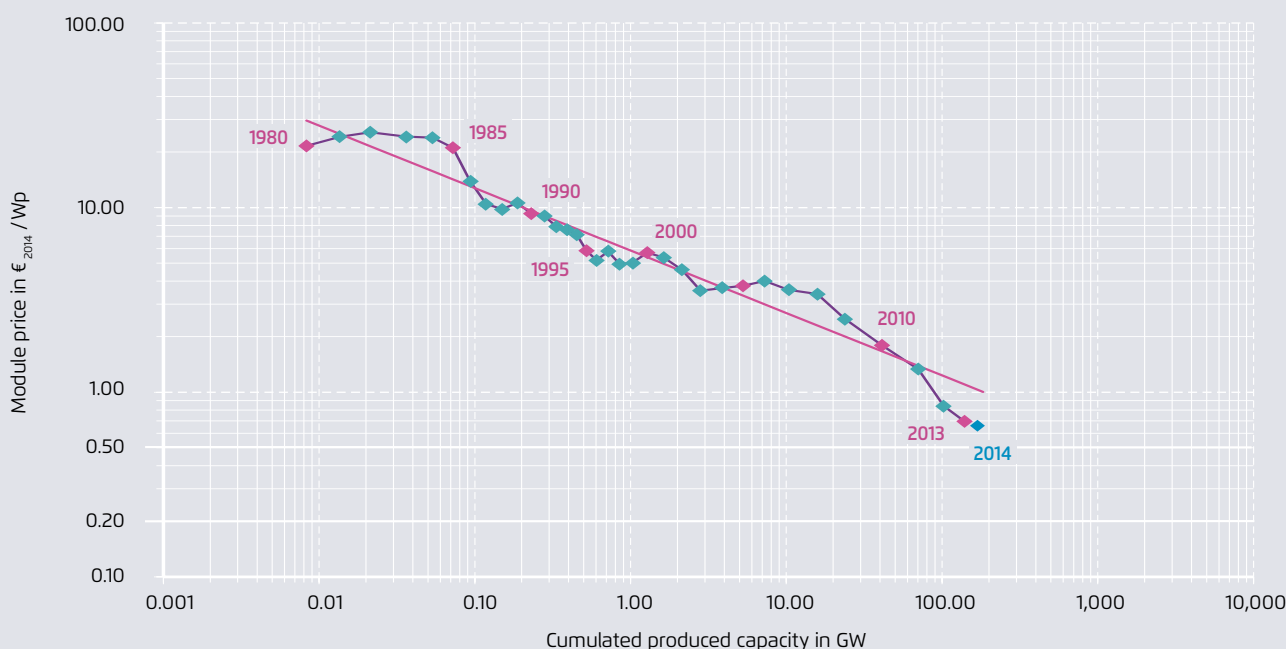
Own illustration

Range of the historical learning rate by variation of the considered time scale

Figure 20

Own illustration

Regarding the first question, our suggestion is that the learning rate can be expected to continue in the long term. Initial analysis performed at Fraunhofer ISE suggest that a critical cost range, where fundamental material cost will dominate the price of modules, will be reached only when prices go as low as 0.1 to 0.2 EUR/Wp (Figure 21). This suggestion was widely supported by the industry experts at the workshops. The learning rate was discussed more controversially, with several experts pointing to different analyses covering different historical time spans that indicate a learning rate of above 23 percent, while other experts suggested that future learning rates might be lower than historical. For the further analysis in this study, we have varied the future long-term learning rate roughly +/- 2 percent around the historical learning rate of 20.9 percent (Figure 20).

The second question was intensively and controversially discussed at the workshops. Several experts expressed the opinion that the current prices are below the current cost of production and an oscillation of the price curve back to

the historical learning curve is likely in the coming years. Other experts shared the opinion that prices reflect the cost of production of the best-in-class producers today and that other producers are likely to invest into equipment upgrades that might lead to even lower production costs in the next years. It was pointed out that Tier-1 module producers in China specify their own module production cost in 2014 below 0.4 EUR/W and that with incremental improvements alone significant further cost reductions can be expected in the coming years – both driven by cell efficiency improvement and material cost reduction (reduced kerf losses, reduced use of silver, etc).

Based on the uncertainty of the market developments we have in this study applied a conservative assumption on future price development: We assume that the price of modules will return to the historical price experience curve in the long term at a cumulated produced capacity of 5000 GW. This implies a very conservative 10.3 percent price learning rate until this cumulative capacity is reached. A look back at Figure 15 shows that in the pessimistic scenario 1 this is

the case only in 2050 – thus in this scenario the historical learning rates are by far not reached again. Even in the PV breakthrough scenario, this conservative assumption results in a reduced learning rate of 10.3 percent for the next 15 years.

Combining these assumptions on the future development of the price experience curve with the scenarios of market development described in Section 3.4 leads to future prices of modules between 140 and 350 EUR/kWp in 2050. Table 3 lists the results of this analysis in detail.

Cost for PV modules in 2050 in different scenarios (price for investor)   Table 3

Learning rate	Scenario 1	Scenario 2	Scenario 3	Scenario 4
19%*	35.7 ct_{EUR}/Wp	30.4 ct_{EUR}/Wp	25.7 ct_{EUR}/Wp	20.9 ct_{EUR}/Wp
20.9%**	31.5 ct_{EUR}/Wp	26.4 ct_{EUR}/Wp	21.9 ct_{EUR}/Wp	17.5 ct_{EUR}/Wp
23%***	27.3 ct_{EUR}/Wp	22.3 ct_{EUR}/Wp	18.1 ct_{EUR}/Wp	14.0 ct_{EUR}/Wp

Own calculation

Extrapolation of the price experience curve for PV modules   Figure 21
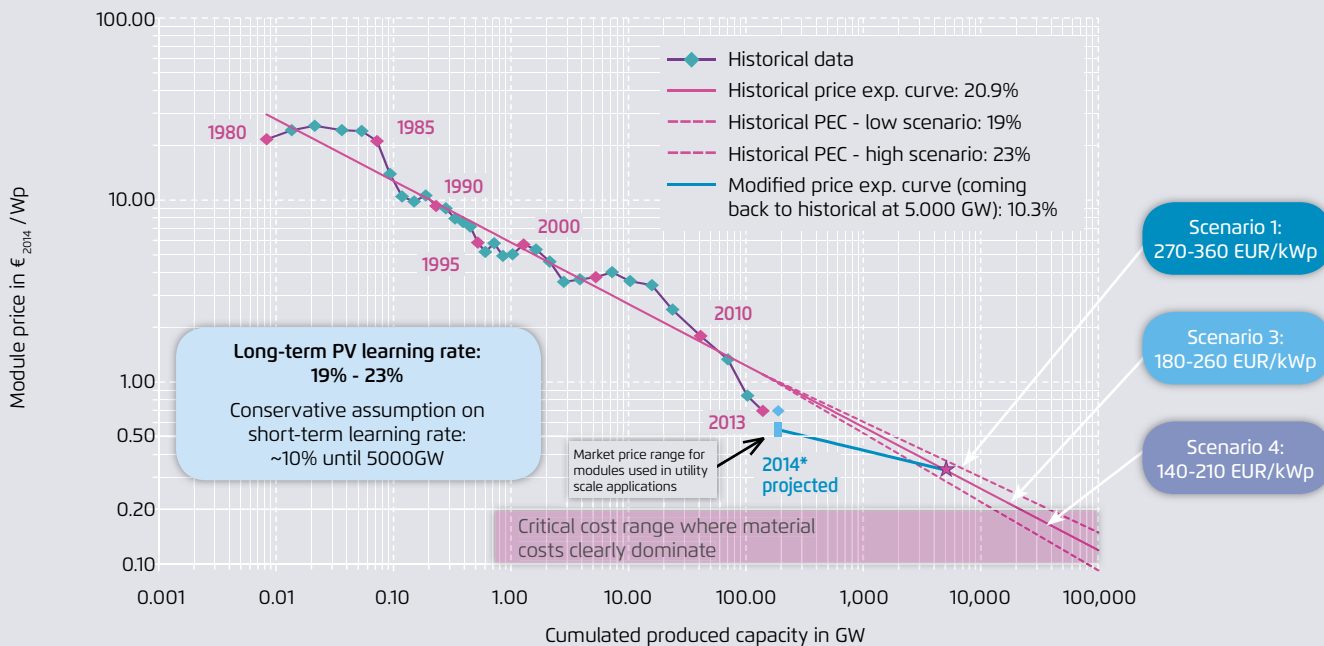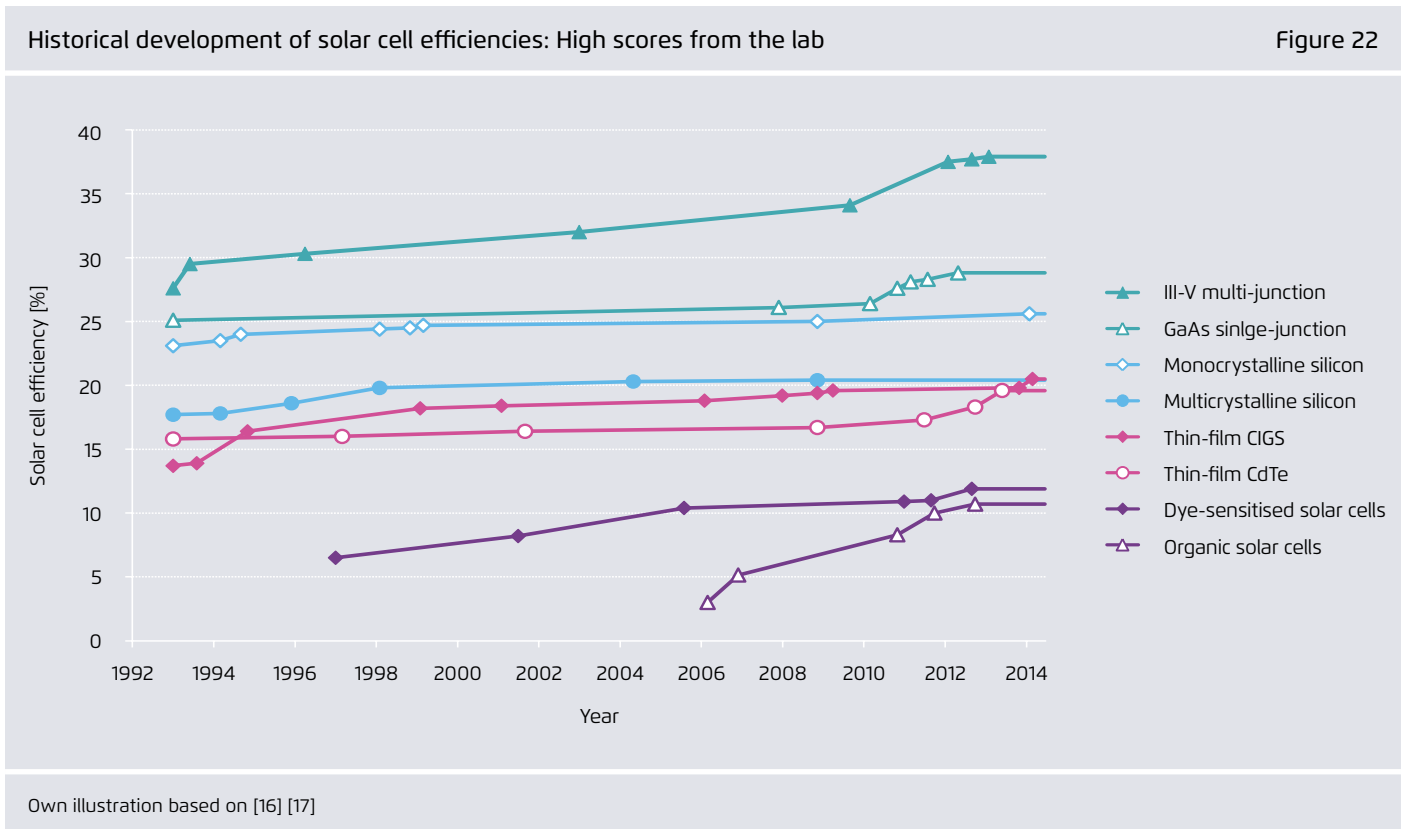

Own illustration

4.3 Scenarios for future module efficiency

Increasing the efficiency of a photovoltaic device is the aim of many research and development efforts. A higher efficiency produces the same amount of electrical power on a smaller area, i.e. less material is needed. This opens a path for reducing costs and allows for business opportunities. Figure 22 illustrates the progress in efficiency records of laboratory solar cells from different materials in the last decades.

The key for high efficiency is that a photovoltaic device transforms as much energy of the photons in the solar spectrum as possible into electrical energy. The part of the spectrum that can be used by a conventional single-junction solar cell is determined by the bandgap of its semiconductor material. Photons with energies below the bandgap are not absorbed and therefore always lost. Photons with energy higher than the bandgap are typically well absorbed but the excess energy beyond the bandgap is lost by thermalisation processes. These limitations determine a maximum theoretical efficiency for single-junction solar cells under the standard AM1.5g spectrum with no light concentration of 33 percent [18]. The underlying detailed balance approach, which was developed by Shockley and Queisser as early as 1961 [19], assumes an idealised solar cell composed of perfect and in particular direct semiconductor material with the optimal bandgap (1.34 eV). Semiconductors like silicon and GaAs are close to this optimal bandgap and record efficiency values of 25.6 percent and 28.8 percent have already been reached in the laboratory. However, as silicon is an indirect semiconductor, the theoretical efficiency limit is significantly lower due to inevitable recombination losses. This leads to a theoretical cell limit for crystalline silicon solar cells of 29.4 percent under AM1.5g [20]. Due to several practical limitations, e.g. recombination at contacts, the theoretical values will never be reached (see discussion in [21]). For crystalline silicon solar cells in the laboratory it is assumed that 28 percent can be reached. The industrial cell limit is seen by 26 percent [22]. Inevitable losses in the module cause a further reduction leading to an industrial module limit of 25 percent. It can be assumed that such high-end modules

Historical development of solar cell efficiencies: High scores from the lab Figure 22

Own illustration based on [16] [17]

will be available in 2050. However, an industry standard of 24 percent is assumed for 2050.

It should be noted that flat-plate modules made of GaAs single-junction solar cells have recently reached an efficiency of 24.1 percent [17]. Efforts are ongoing to commercialise such modules, e.g. [23]. Although this is a promising route for high efficiency flat-plate modules, it is not yet clear when and if cost competiveness with flat-plate modules made of crystalline silicon will be reached.

An effective and practical path for high efficiency solar cells is the multi-junction approach. The idea is to stack several solar cells of different semiconductor material with increasing bandgaps on top of each other in order to (i) exploit a larger part of the solar spectrum and (ii) reduce the thermalisation losses. Hence, each subcell converts a specific part of the sun´s spectrum, which leads to theoretical efficiency limits of 46 percent for dual-junction and 52 percent for triple-junction solar cells under AM1.5g without concentration, again based on the approach of Shockley and Queisser [24]. The definition of a multi-junction solar

cell architecture is carried out in three steps. First, an optimal band combination is determined, e.g. based on theoretical calculations. Second, suitable materials are chosen. And finally the architecture needs to be realised. While the first two steps are relatively easy, the realisation of such a device can be technically challenging. Multi-junction solar cells made of III-V semiconductors have become standard in space applications as well as in concentrator photovoltaic (CPV) systems on earth, e.g. [24]. Different routes are currently being investigated to realise cost-competitive flat-plate modules with multi-junction solar cells. A promising route is to realise Si-based dual-junction solar cells with a bottom cell of silicon and a higher bandgap material on top of that. Possible candidates are III-V semiconductors, Perovskite or silicon quantum dots. These approaches can achieve practical efficiencies of up to 35 percent. For even higher practical efficiencies significantly above 35 percent, triple-junction solar cells are required. The technical feasibility of several of the advanced approaches has already been shown in the lab. However, intensive research is still necessary to bring these technologies closer to commercialisation.

Overview of flat-plate module efficiency scenarios   Figure 23

Own illustration
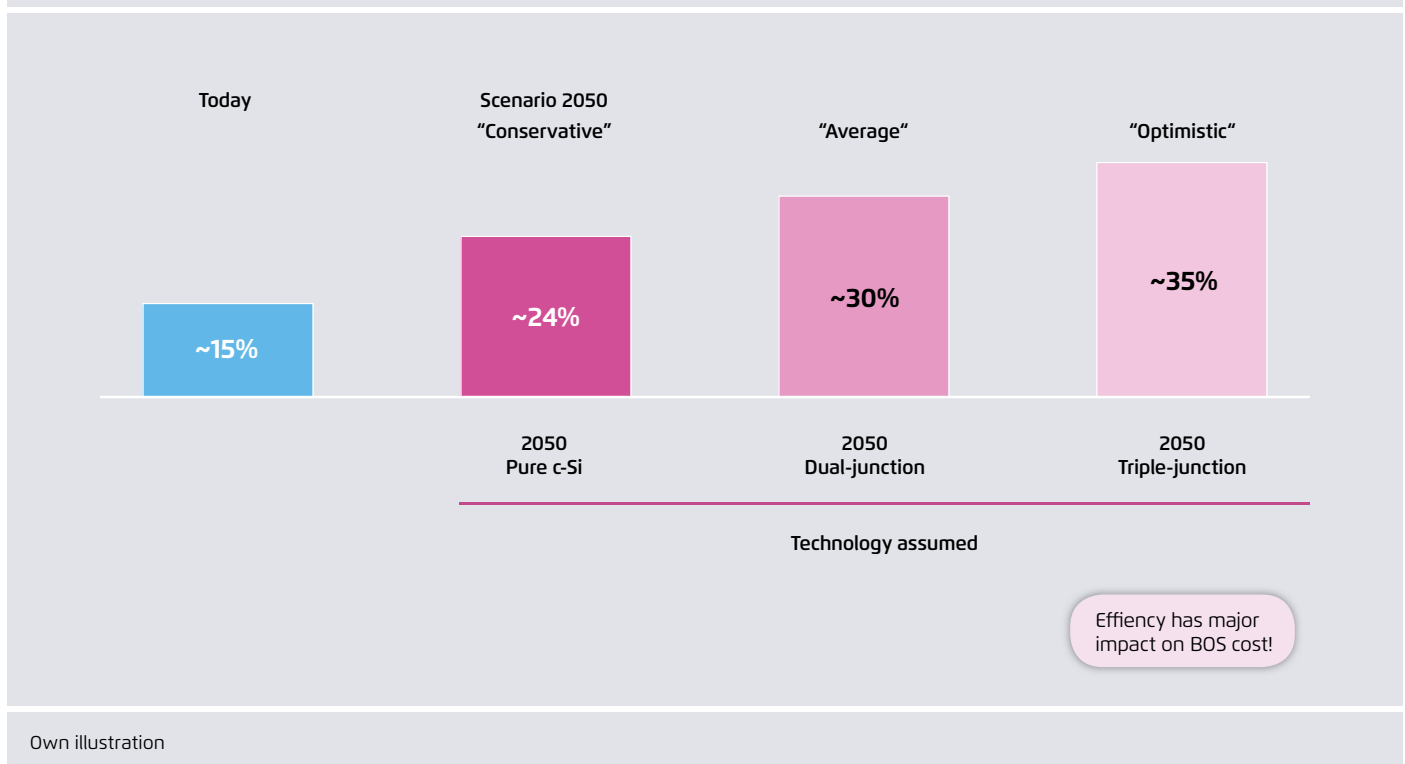
To account for uncertainty in future technology and market development, different scenarios of future module efficiency (flat plate without concentration technology) are used for further analysis in this study, summarised in Figure 23. These module efficiencies determine the physical size of the surface of the PV power plant needed to generate a certain electricity output and thus have a significant impact on the balance of system cost (see Section 5.1).
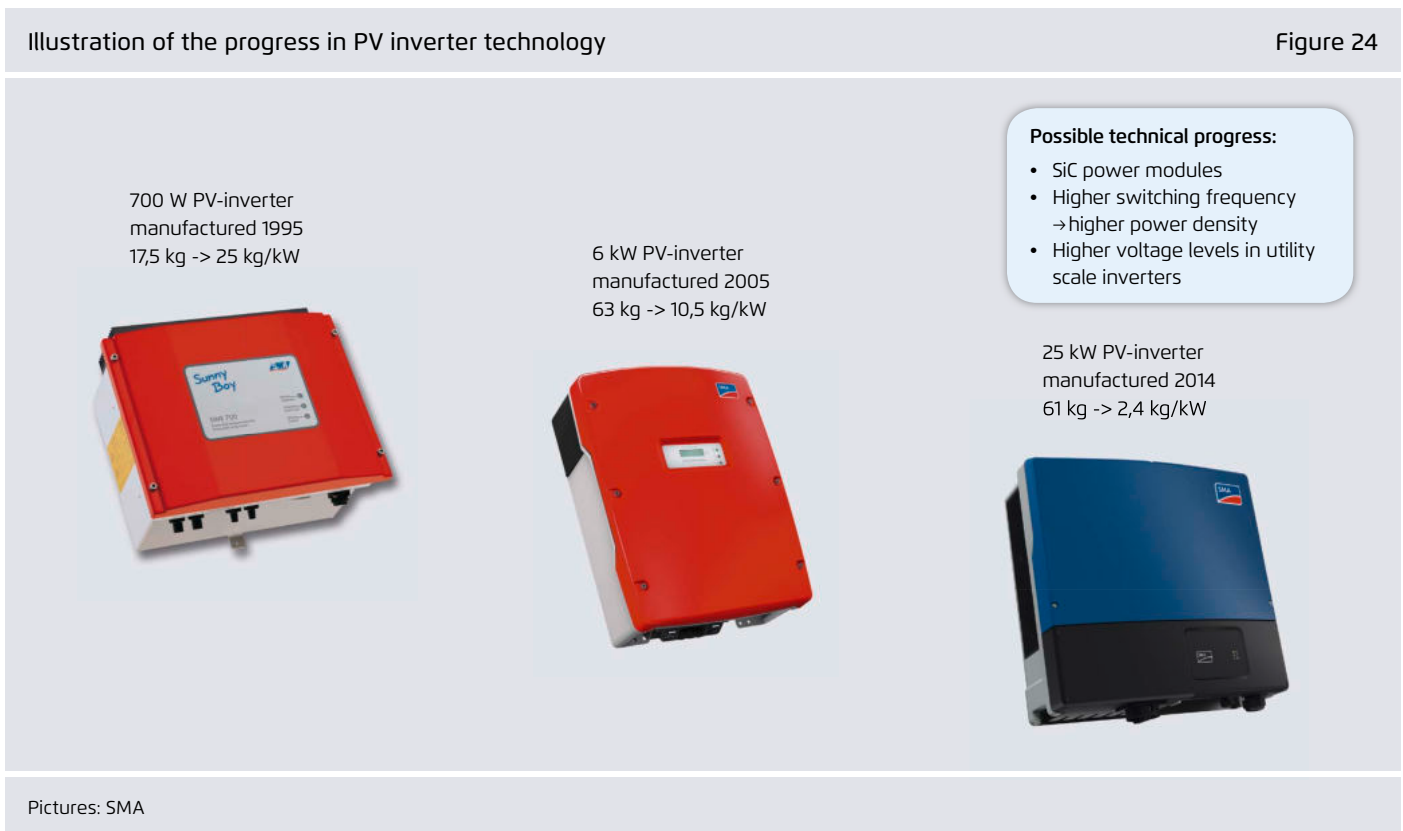
4.4 Learning curve of PV inverters

Impressive progress has been achieved during the last decades not only at the module / cell level of photovoltaics, but also in the inverter technology: costs came down from over 1 EUR/Wp in 1990 to almost 0.10 EUR/Wp 2014; efficiencies and power density have increased significantly. Main drivers for this development were improved power semiconductors and new circuit topologies. At the same time inverters became "smarter" by offering advanced monitoring and communication interfaces that help to improve the availability and performance of PV installations. Further-

more, new inverter generations can help to stabilise the power grid by providing reactive power and featuring low-voltage ride-through (LVRT) during grid errors.

Figure 24 shows how size and weight of inverters have improved over the last decades. New power semiconductors based on silicon carbide technology, higher switching frequencies and higher voltage levels in utility scale inverters are promising approaches for further improvements in PV inverters.
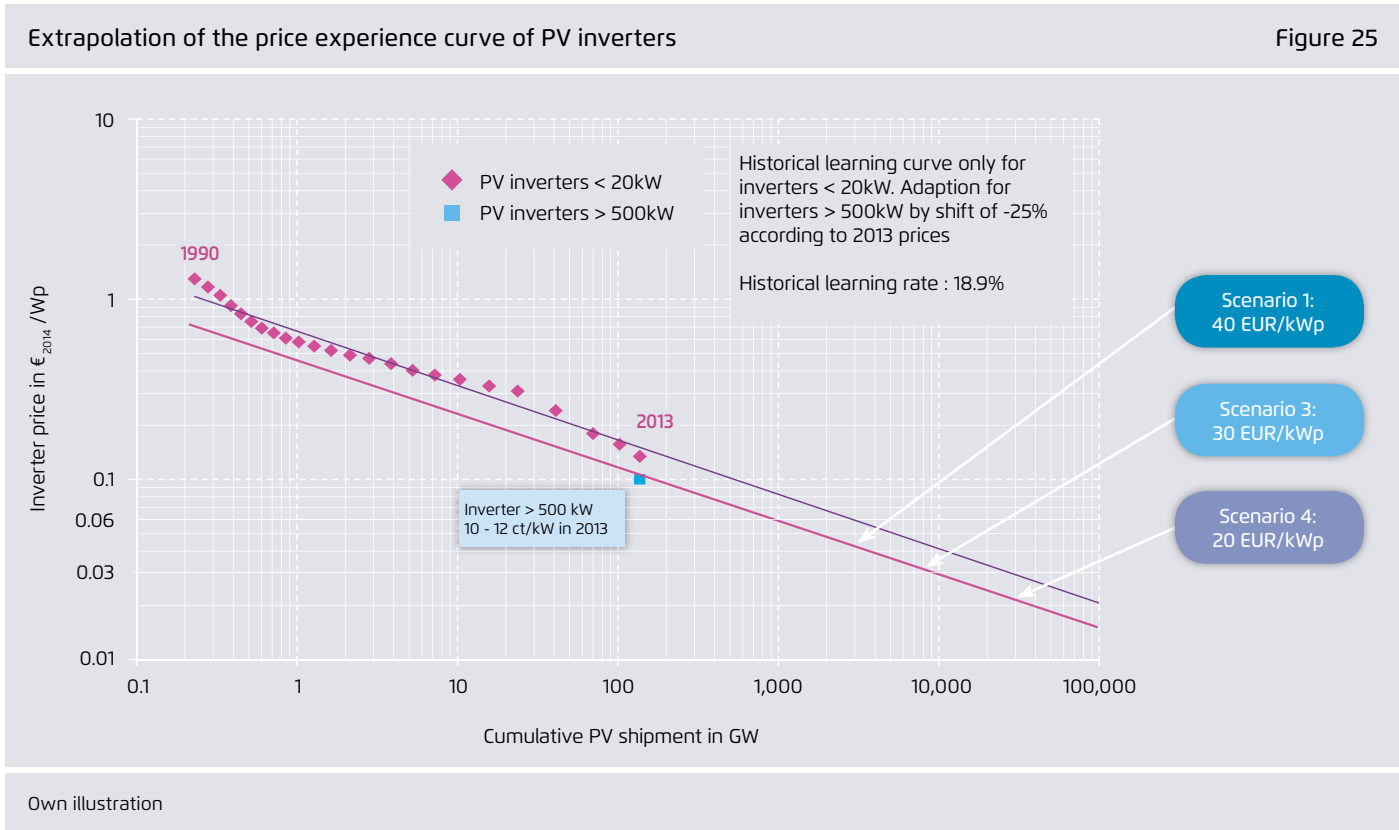
Like for the PV modules, we choose a learning curve approach to estimate the future cost reduction of PV inverters. Figure 25 shows the extrapolation of the historical learning curve that is based on data provided by SMA, with a learning rate of 18.9 percent. The historical price data is only available for inverters with less than 20 kW rated power, which have higher specific costs than large scale inverters with several hundred kilowatt power. To project the prices for utility scale inverters, we shift the historical learning curve according to prices of inverters >500 kW reported for

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Illustration of the progress in PV inverter technology   Figure 24

700 W PV-inverter
manufactured 1995
17,5 kg -> 25 kg/kW

6 kW PV-inverter
manufactured 2005
63 kg -> 10,5 kg/kW

Possible technical progress:
- SiC power modules
- Higher switching frequency
  →higher power density
- Higher voltage levels in utility
  scale inverters

25 kW PV-inverter
manufactured 2014
61 kg -> 2,4 kg/kW

Pictures: SMA

2013, which are in the range of 100 to 120 EUR/kW, assuming the same learning rate of 18.9 percent. Depending on the PV market scenario, our assumptions on PV inverters result in inverter prices of 21 to 42 EUR/kW in 2050. Table 4 lists the resulting cost of PV inverters the 4 market scenarios considered in detail.

Cost for PV inverters in 2050 in different scenarios				Table 4
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Min	3.5 ct$_{EUR}$/Wp	3.0 ct$_{EUR}$/Wp	2.6 ct$_{EUR}$/Wp	2.1 ct$_{EUR}$/Wp
Max	4.2 ct$_{EUR}$/Wp	3.6 ct$_{EUR}$/Wp	3.1 ct$_{EUR}$/Wp	2.5 ct$_{EUR}$/Wp

Extrapolation of the price experience curve of PV inverters   Figure 25

Own illustration

5 Cost projection for other system components (BOS)

5.1 Methodology explained: Estimating future BOS costs

For projecting the prices of PV modules and inverters we used a price experience curve approach. Since there is no long-term historical price data available for the BOS (balance of system) components and unlike modules and inverters, non-technology cost such as planning, licensing and local infrastructure are included, this approach seems less suitable to project future BOS costs. We therefore apply a detailed component-based analysis to develop scenarios for future BOS costs.

To develop an appropriate set of scenarios, the key drivers for cost reduction were discussed for each of the different BOS components. We found module efficiency, DC-voltage increase and system size to be key drivers amongst other, component-specific drivers. The table in Figure 26 sum-marises the BOS components and the key drivers by which they are influenced.

Module efficiency was identified as the single, most influential factor on BOS cost. Figure 27 illustrates the effect of increased module efficiency. Today, the area of a PV power plant with 1 MW power and 15 percent module efficiency is comparable to the size of two soccer fields. By doubling the module efficiency, the surface would shrink to 50 percent which equals one soccer field in our example of a 1-MW power plant. Consequently, all area-related costs like the installation or the mounting structure in the power plant would be significantly lower. Assuming that exactly the same setup is chosen for a 2-MW PV power plant with modules at 30 percent efficiency as for a 1-MW PV power plant with modules at 15 percent efficiency, the specific area-related cost would even be exactly 50 percent lower in the case of the higher efficiency modules: cost for installa-

Impact of key drivers on BOS components				Figure 26
BOS cost component	**Key drivers for cost reduction**			
	Module efficiency	**System size**	**DC-voltage increase**	**Other**
Installation	X			X
Mounting structure	X			X
DC cabling	(X)		X	X
Grid connection		X		
Infrastructure	(X)			
Planning & documentation	(X)	X		
Transformer			X	

Own illustration

tion, mounting structure, fencing and roadwork would be identical between the two power plants, yet one having an output of 2 MW and the other an output of 1 MW.

Based on the initial analysis and the discussions at the workshops, a systematic approach was developed to estimate and calculate scenarios of future BOS costs. This approach follows a set of three questions, separating the different effects that drive future reduction in BOS costs and allowing a separate discussion on each specific question.

Starting from typical BOS costs today, an upper and lower estimation of long-term cost reduction in each component of BOS costs is required, assuming that the module efficiency would remain unchanged. In the case of installation cost (example depicted in Figure 28), the expert discussions resulted in an estimation of approx. 50 EUR/kWp today and a cost reduction potential of only 10 percent until 2050 in the worst case and 40 percent in the best case.

A separate estimation is then done regarding the effect that a duplication of module efficiency has on each of the components of BOS cost. In the case of installation, the effect of duplication is straightforward, as the same size of module installed would merely produce twice the power. In a final step, the resulting range of cost per component is calculated for each of the three module efficiency scenarios. The detailed analysis for the different BOS components is described in Section 5.3.

A second relevant driver identified in the analysis above (Figure 26) is the system size. In the further analysis of BOS cost we assume that, in the long term, average size of ground-mounted PV systems will increase from roughly 1 MW to roughly 10 MW. Against the background of current discussions of "mega"-scale projects in countries such as India, this appears to be a small size for ground-mounted systems but was used as a conservative assumption on future system sizes e.g. in Germany.

Illustration of the total land area needed for a 1-MW PV power plant. Module efficiency has a large impact on the surface area and therefore on the BOS cost — Figure 27
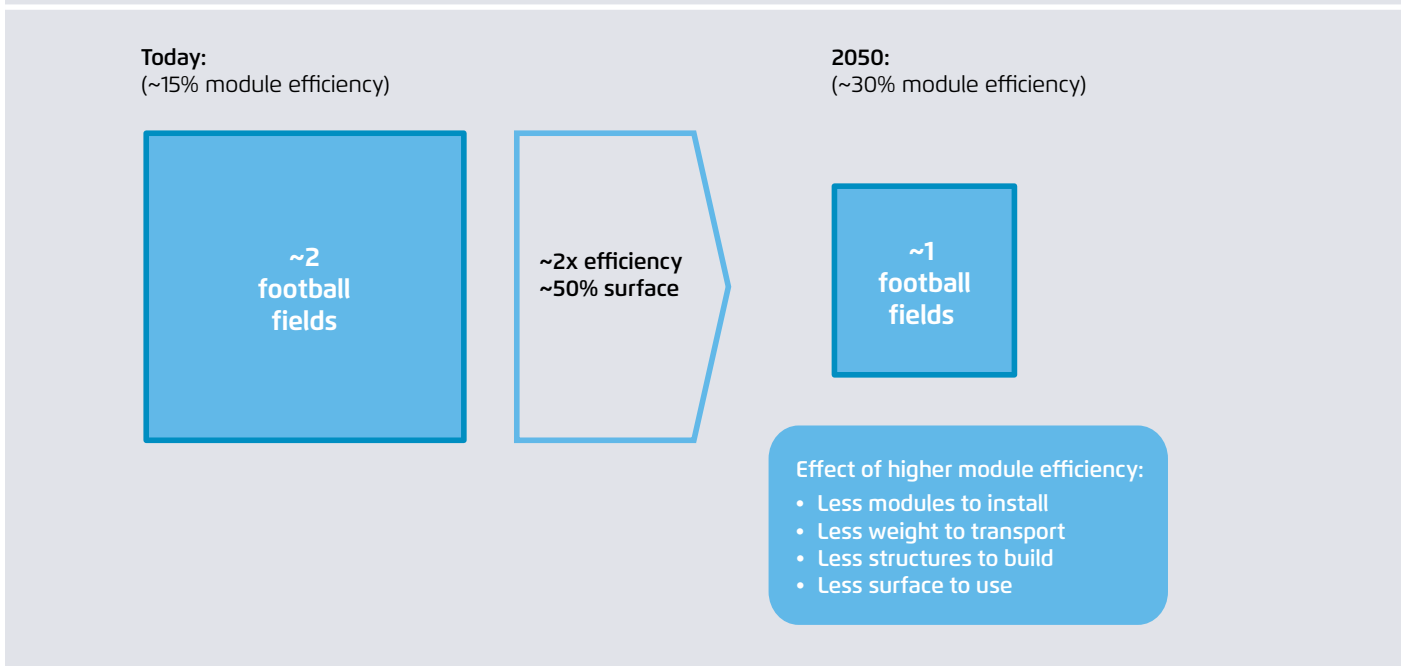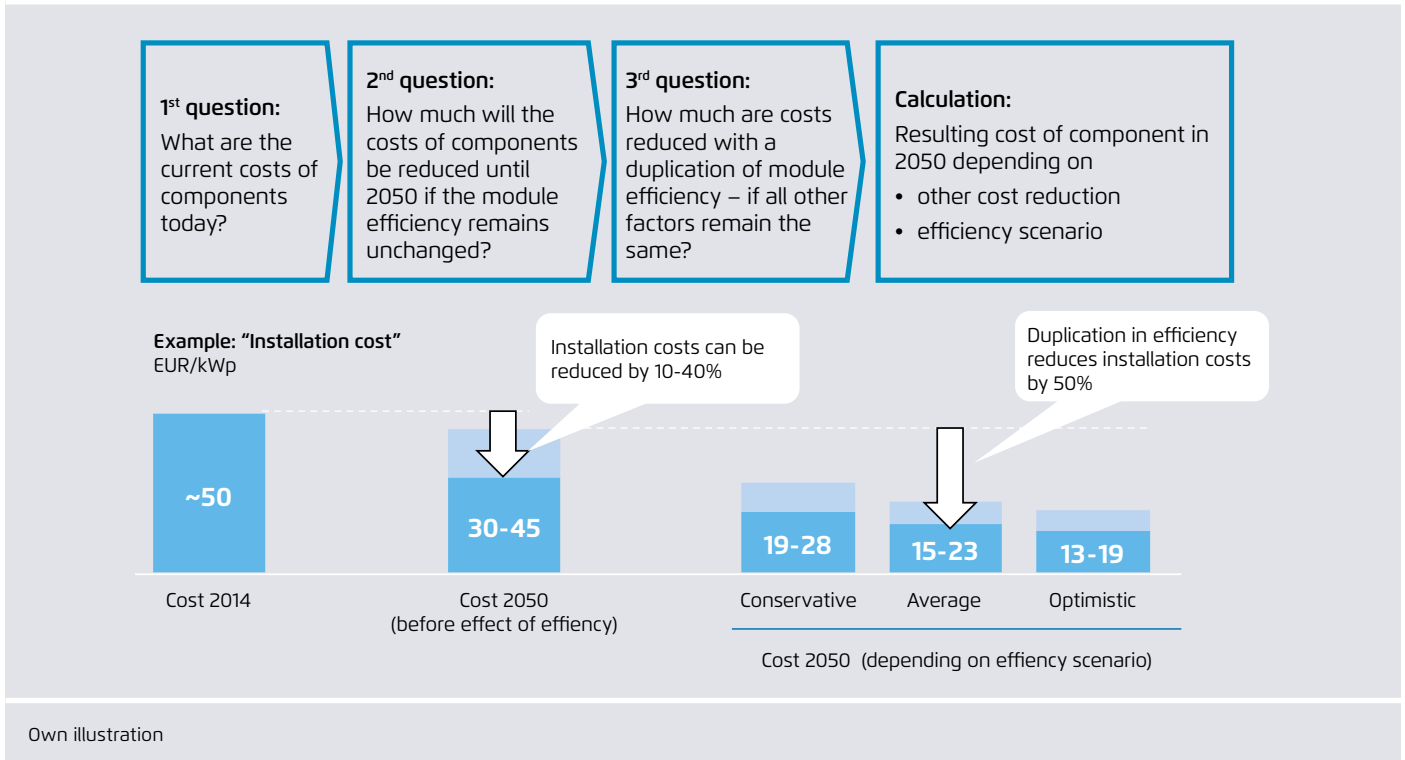

Own illustration

* Football field (Fifa) = 7140 m²

Example of approach to estimate the future Balance of System Cost for each component   Figure 28

1ˢᵗ question:
What are the current costs of components today?

2ⁿᵈ question:
How much will the costs of components be reduced until 2050 if the module efficiency remains unchanged?

3ʳᵈ question:
How much are costs reduced with a duplication of module efficiency – if all other factors remain the same?

Calculation:
Resulting cost of component in 2050 depending on
• other cost reduction
• efficiency scenario

Example: "Installation cost"
EUR/kWp

Installation costs can be reduced by 10-40%

Duplication in efficiency reduces installation costs by 50%

~50
Cost 2014

30-45
Cost 2050
(before effect of effiency)

19-28
Conservative

15-23
Average

13-19
Optimistic

Cost 2050 (depending on effiency scenario)

Own illustration

5.2 Overview on today's Balance of System cost

For the projection of future cost it is necessary to assess the current cost of a PV system first. We choose a typical cost range for a ground-mounted PV system with the size of approximately 1 MW in Germany (representing a mature market) as a starting point. In this context, cost is understood as the cost for an investor, so there is a margin for the system integrator included in the cost of every system component. Based on own analyses and discussions in the workshops, a representative cost range is from 935 to 1055 EUR/kWp, with an average system cost of approximately 1000 EUR/kWp. It has been stressed by several experts that best-in-class and large-scale systems can reach significantly lower system prices already today, both in Germany as well as in several developing PV markets across the globe. However, the suggested cost range was generally supported as a conservative estimate of a representative cost range in Germany in 2013/2014.

Figure 29 shows the cost components of a typical PV ground-mounted system. Today, the module has the highest share of the system costs with around 55 percent. The inverter share is about 11 percent and the BOS the second highest share with 34 percent.

These BOS costs can be divided into main components as shown in Figure 30.
The two largest cost components are mounting with approx. 75 EUR/kWp and grid connection with approx. 60 EUR/kWp. Installation and DC-cabling each cost around 50 EUR/kWp and infrastructure around 40 EUR/kWp.

The remaining BOS cost components are the transformer, switchgear and planning and documentation with a joint cost of approx. 60 EUR/kWp.

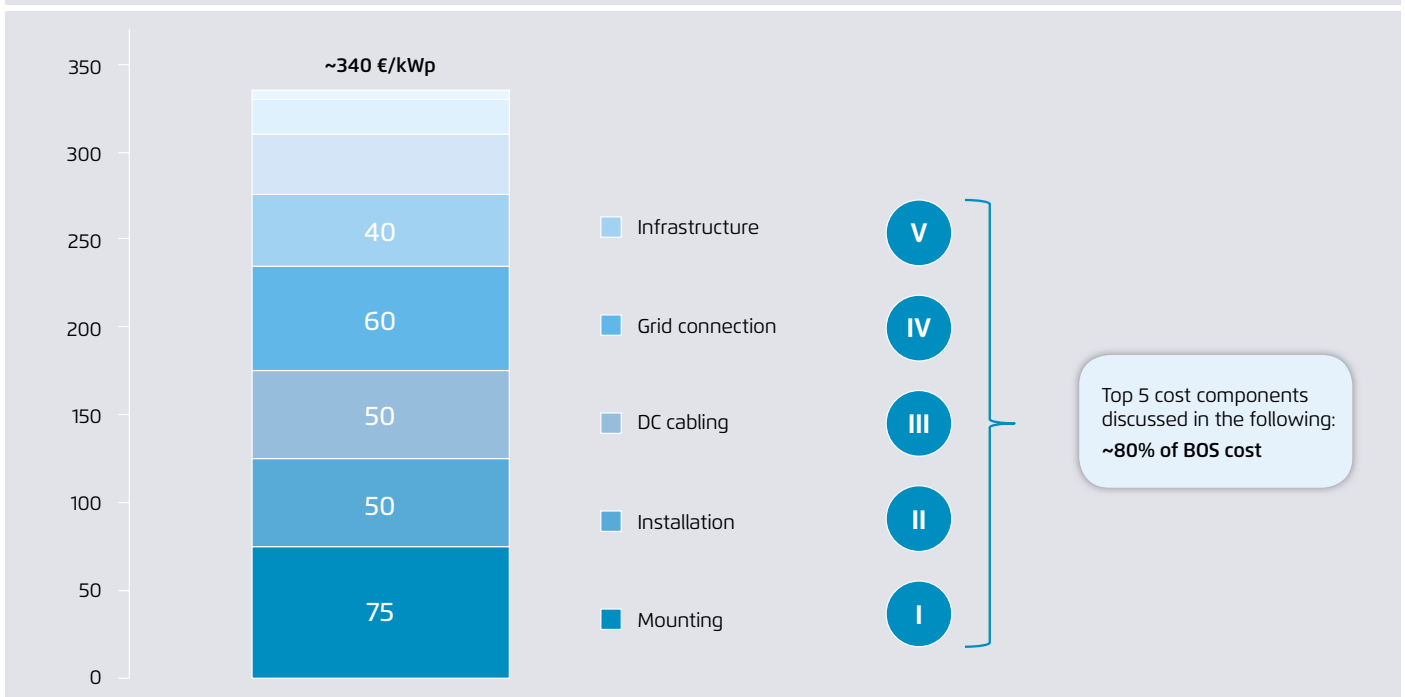**Overview of today's total system cost for ground-mounted PV systems (example from Germany)**   Figure 29

Total: ~1000 €/kWp

~340   } Balance of System cost

~110

~550   Module and inverter: ~ 660 EUR/kWp [world market]

"BOS" (= "Any other components")
- Mounting system
- Installation
- Cable (DC)
- Infrastructure
- Transformer
- Grid connection
- Planning and documentation
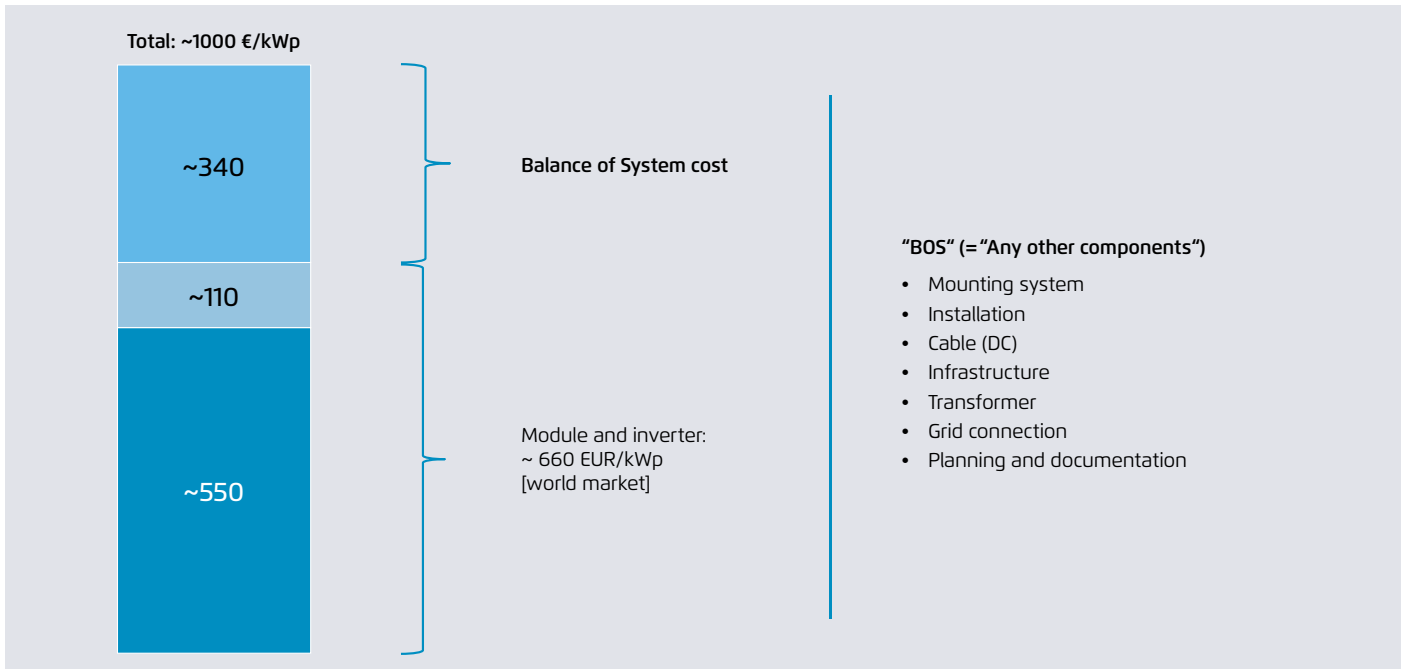
Own illustration   * "Cost" here: Prices paid by system integrator; price paid by investors may be higher; cost in countries with less competitive markets for PV may be higher

---

Overview of Balance of System cost for ground-mounted PV systems (example from Germany)   Figure 30

~340 €/kWp

40	
60	
50	
50	
75	

■ Infrastructure   V

■ Grid connection   IV

■ DC cabling   III

■ Installation   II

■ Mounting   I

Top 5 cost components discussed in the following: **~80% of BOS cost**

Own illustration

5.3 Detailed analysis on BOS cost reduction potentials

As shown in the last section, mounting, installation, DC cabling, grid connection and infrastructure amount for nearly 80 percent of the BOS cost. The cost reduction of these five components is described in detail in the following; the components of planning and documentation, transformer and switch gear are summarised in one paragraph at the end of this Section. The possible future cost developments of the components presented in the following were discussed, based on initial analysis, at the workshops and in expert interviews with a number of project developers and service providers, yet are subject to a significant variation and uncertainty.

I Mounting structure

The mounting structure considered here includes the physical structures that are used to hold the PV modules in a defined position over the lifetime of the PV power plant, but not the cost of installation of these structures. Typical costs today are around 75 EUR/kWp.

It is assumed that until 2050, the cost reduction that is not driven by module efficiency will be only 20 percent in the worst case and up to 50 percent in the best case. These assumptions on cost reduction are based on the understanding that raw material cost will continue to make up a significant part of the cost while the introduction of new materials is possible (best case assumption) but uncertain (worst case assumption). An obvious cost reduction potential exists in future standardisation and scale effects, achieved by increasing global markets and larger PV power plants.
In case of east-west-oriented PV a lower cost (per installed kWp) is possible than in case of a south-oriented power plant.

The impact of a duplication of module efficiency on the cost of the mounting structure is a reduction by 50 percent, as an increased power output per module reduces the rela-

Cost reduction scenario for the mounting structure Figure 31

20%-50%

50%-79%

~75 EUR/kWp

~38-60 EUR/kWp

~16-38 EUR/kWp

Cost 2014

Cost reduction 2050 (before eff.)

Cost 2050 (incl. efficiency effect)

Own illustration, based on expert workshops, picture: Schletter
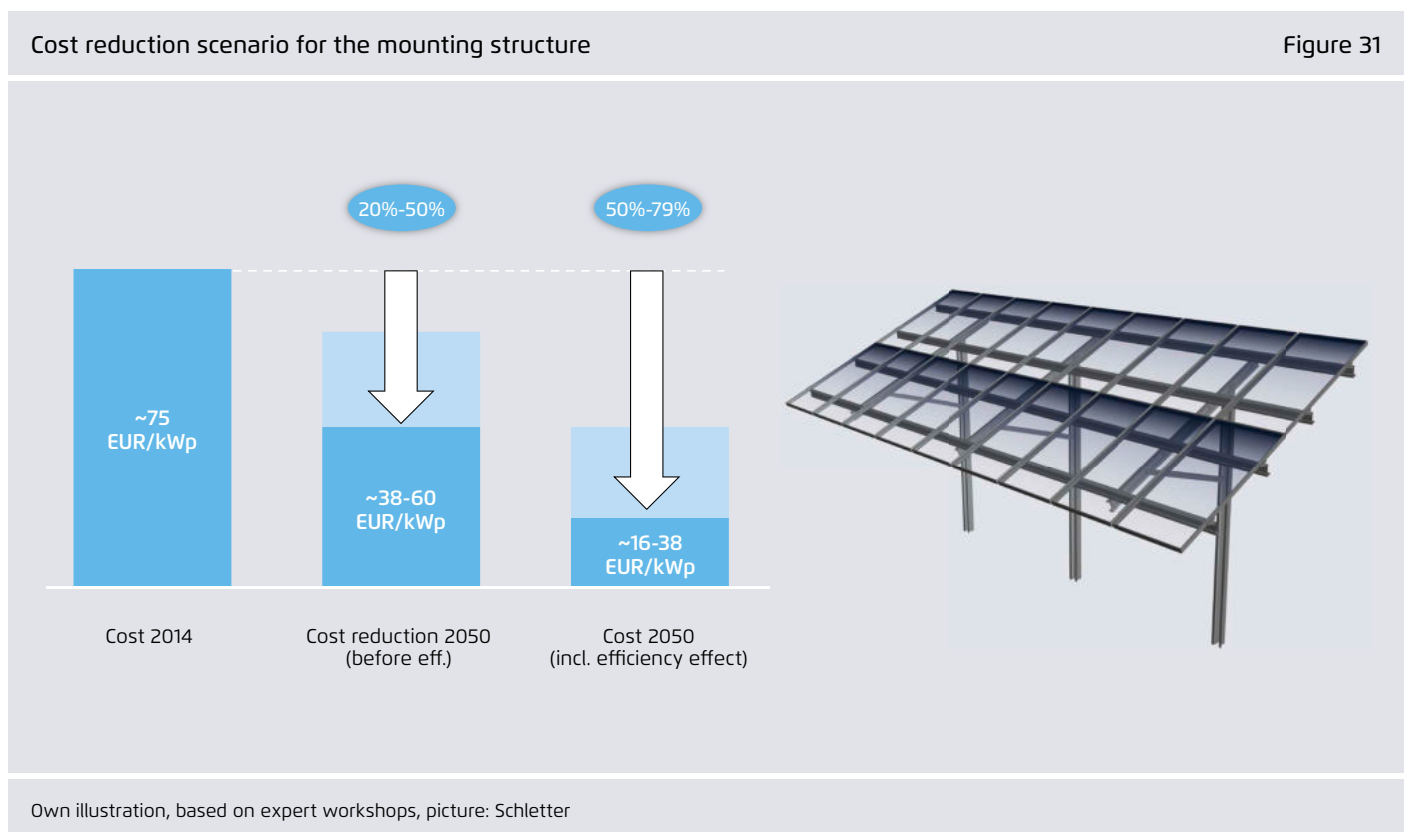
tive cost of the mounting structure proportionally. Thus the "efficiency impact factor" is estimated at 100 percent.

The resulting costs for mounting structures in 2050 are calculated to range from 16 to 38 EUR/kWp (Figure 31), with the 16 EUR/kWp resulting from the combination of the best-case cost development with the "optimistic" module efficiency scenario (including an increase of module efficiency from today 15 to 35 percent in 2050).

II Installation of ground-mounted PV systems

The installation costs include the assembly of the mounting structure, the installation of the modules on the mounting structure as well as the work required to connect the modules to the inverters. Typical costs today are around 50 EUR/kWp. These costs are made up largely of labour cost, for which in the future an increased productivity can be expected, yet at the same time a roughly proportional increase in real wages. Automation of installation appears possible in the future, but remains highly uncertain. The only cost reduction drivers that were widely acknowledged as cer-

tain were the effect of further standardisation and increasing size of the individual PV power plant. Thus for the worst case, a cost reduction of only 10 percent was assumed and for the best case 40 percent. It has been pointed out by industry experts that significant differences exist in installation costs across the world, with large scale projects in developing countries today achieving significantly lower specific costs than those assumed here.

Similar to the mounting structure, an increased power output per module reduces the relative cost of the installation process proportionally, thus an efficiency impact factor of 100 percent is assumed.

The resulting cost of installation in 2050 is calculated to range from 13 to 28 EUR/kWp (Figure 32), with 13 EUR/kWp resulting from the combination of the best-case cost development with the "optimistic" module efficiency scenario and 18 EUR/kWp resulting from the combination of the worst-case cost development with the "conservative" module efficiency scenario.

Cost reduction scenario for the installation   Figure 32

10%-40%   44%-74%

~50 EUR/kWp

~30-45 EUR/kWp

~13-28 EUR/kWp

Cost 2014   Cost reduction 2050   Cost 2050
                  (before eff.)   (incl. efficiency effect)

Own illustration, based on expert workshops, picture: Schletter
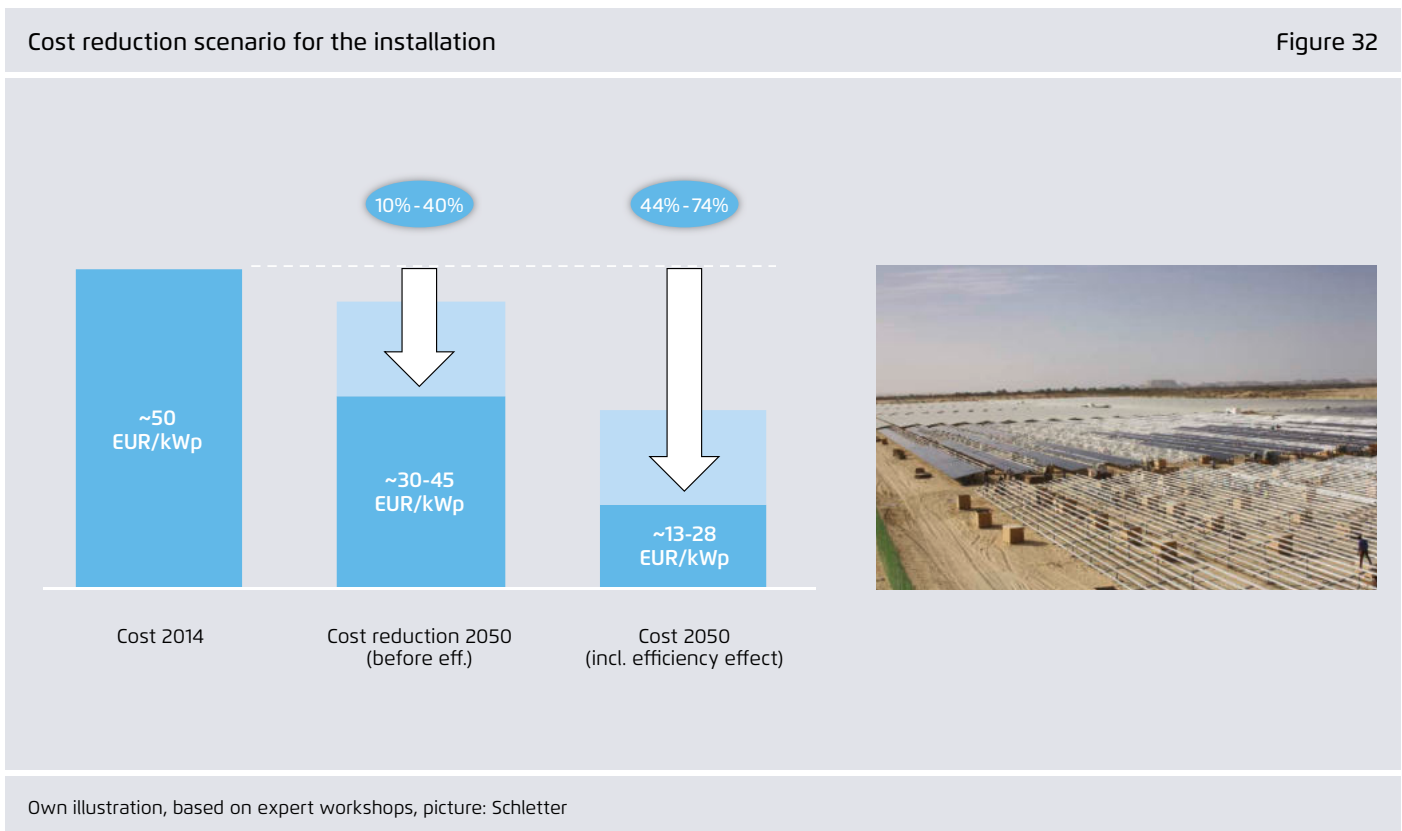
III DC cabling of ground-mounted PV systems

The DC cabling includes all cables used between modules and the DC inverter as well as the combiner boxes for the module strings. A large share of the cost is made up by raw material cost (copper for solar cables and aluminium for collection cables) for which a future increase in price is possible. Future use of aluminium instead of copper for solar cabling (between the modules and the combiner boxes) was discussed at the workshop but appears highly uncertain, since aluminium is more brittle than copper making the handling of thin solar cables (4 – 8 mm² cross-section) very difficult. The cables between combiner boxes and central inverters (120 – 240 mm² cross-sections) are made of aluminium already today. A significant reduction in cost considered to be likely in the future is driven by an increase of DC voltage, reducing the cable cross-section to transport the same amount of power. Costs for the thicker insulation for a higher voltage are overcompensated by the savings in copper or aluminium. Further cost reductions are expected due to standardisation and scale. In the worst case, a cost reduction of 10 percent is estimated, in the best case 30 percent.

The impact of module efficiency is less straightforward than in the case of mounting structures and installation, as a higher output per module reduces the length of solar cables required, but not the amount of power that needs to be transported through the cable and the combiner boxes. To account for this, an efficiency impact factor of 75 percent is assumed.

The resulting cost of DC cabling in 2050 is calculated to range from 20 to 32 EUR/kWp (Figure 33), with the 20 EUR/kWp resulting from the combination of the best-case cost development with the "optimistic" module efficiency scenario and 32 EUR/kWp resulting from the combination of the worst-case cost development with the "conservative" module efficiency scenario.

Cost reduction scenario for the DC cabling Figure 33
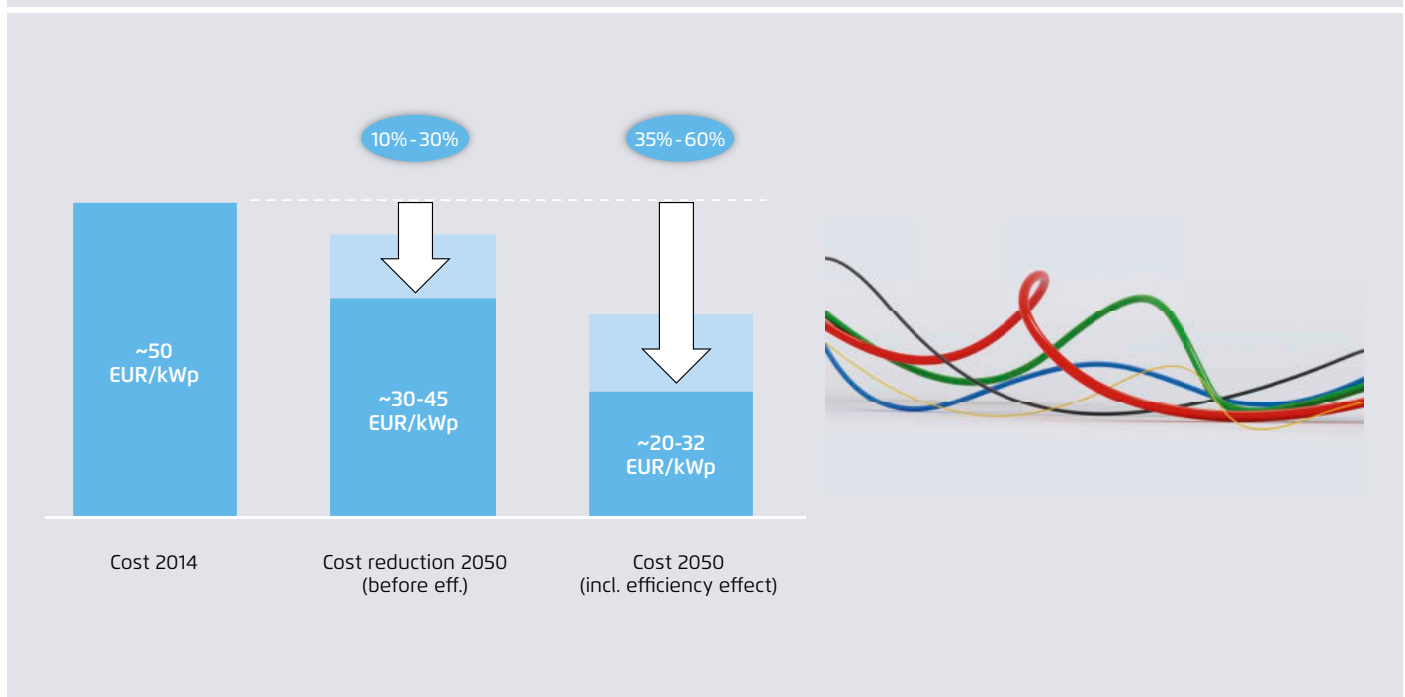
Own illustration, based on expert workshops, picture: iStock/adempercem

IV Grid connection of ground-mounted PV systems

The grid connection includes all costs for connecting the central inverters to the point of access of the distribution grid, including cabling and infrastructure works required but excluding transformers and switchgears.

This cost component appears to be the most location-specific component, depending on the proximity of the grid connection point, which can range from several hundred metres to several kilometres, as well as the effort required to establish infrastructure, including soil structure and possible conflicting infrastructures such as roads. Besides the infrastructure works, raw material (copper/iron) is the key cost driver, for which even an increase in cost is possible in the future. On the other hand, the expected increase in power plant size and the reduced specific size of the power plants offers a significant cost reduction potential, as the infrastructure work to reach the distribution grid remains the same and only a larger sized cable is required (with a cable of a tenfold transmission capacity requiring far less than ten times of raw material).

The future cost reduction is therefore assumed to range between 50 percent in the worst case and 60 percent in the best case.

The module efficiency does not have any direct impact on the cost of grid connection; the efficiency impact factor is assumed to be 0 percent.

The resulting cost of grid connection in 2050 ranges from 24 to 36 EUR/kWp (Figure 34), resulting only from the worst- and best-case cost assumptions and without influence of the module efficiency scenarios.

Cost reduction scenario for the grid connection · Figure 34

40%-60%   40%-60%

~60 EUR/kWp

~24-36 EUR/kWp

~24-36 EUR/kWp

Cost 2014

Cost reduction 2050 (before eff.)

Cost 2050 (incl. efficiency effect)

Own illustration, based on expert workshops, picture: Fotolia/Zauberhut
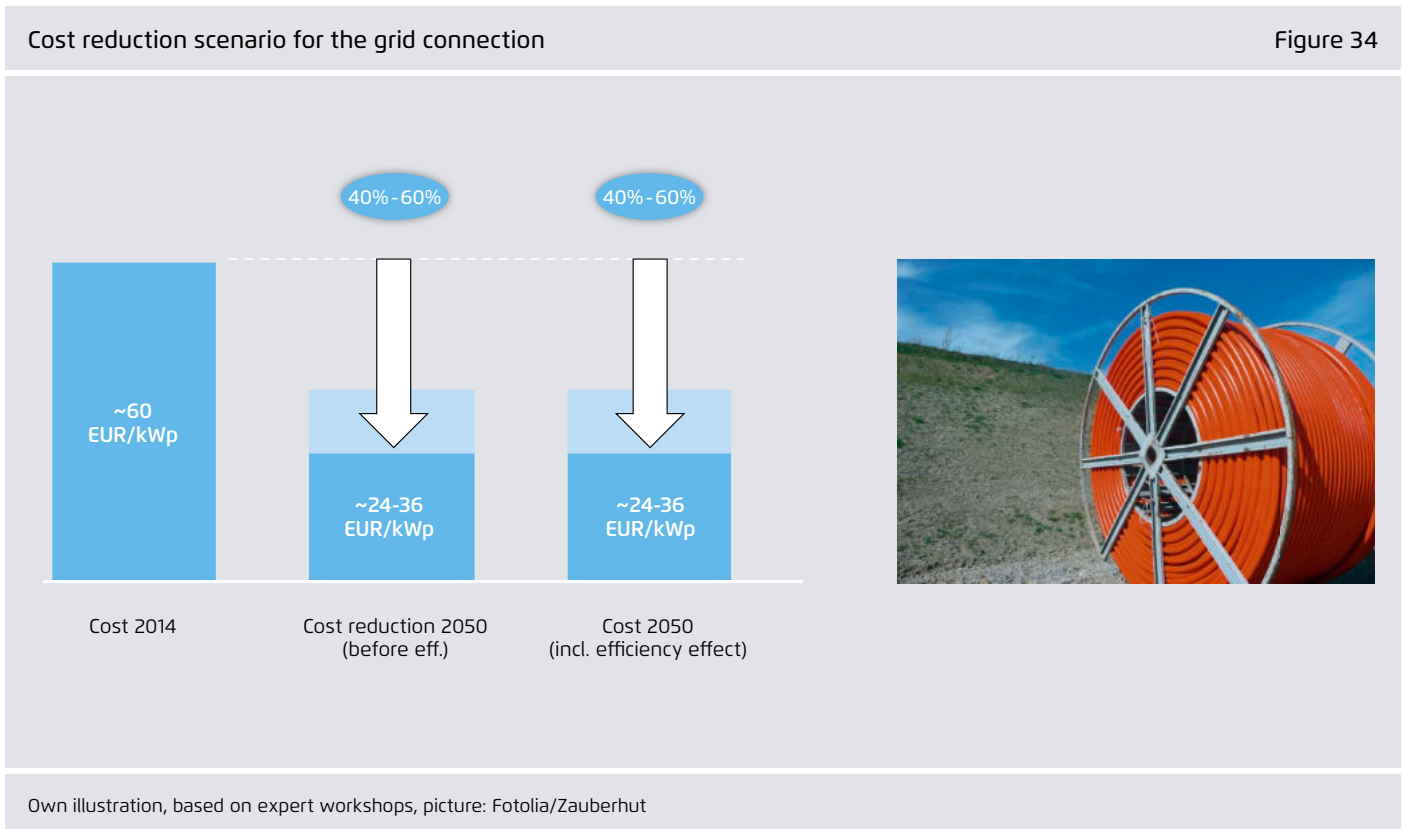
V Infrastructure of ground-mounted PV systems

Infrastructure includes all initial costs to prepare the physical infrastructure of the PV power plant, including fencing, roadwork, etc. and excluding the cost components mentioned above. This cost component is largely made up of labour cost and is very site-specific. Long-term cost reduction potential is expected due to an increasing standardisation and modularisation of PV power farm projects in a globally maturing industry and due to the increasing size of power plants. In the worst case, a cost reduction of only 10 percent is estimated and in the best case 30 percent.

In case of a duplication of module efficiency, the same area for which infrastructure needs to be prepared can be used for twice as much power production. Unlike the module-related cost for mounting structures and installation, infrastructure costs include certain PV-farm-related components (i.e. maintenance of buildings). Therefore costs in the different module efficiency scenarios are not directly proportionally to module efficiency (i.e. a 10-MW PV plant may require twice the surface compared to a 10-MW PV plant of modules of double efficiency, but costs are not twofold). The efficiency impact factor is therefore estimated at 75 percent.

The resulting cost of infrastructure in 2050 is calculated to range from 16 to 26 EUR/kWp (Figure 35), with the 16 EUR/kWp resulting from the combination of the best-case cost development with the "optimistic" module efficiency scenario and 26 EUR/kWp resulting from the combination of the worst-case cost development with the "conservative" module efficiency scenario.

Cost reduction scenario for the infrastructure Figure 35

10% - 30%   35% - 60%

~40 EUR/kWp

~28-36 EUR/kWp

~16-26 EUR/kWp

Cost 2014   Cost reduction 2050 (before eff.)   Cost 2050 (incl. efficiency effect)

Own illustration, based on expert workshops, picture: Belectric
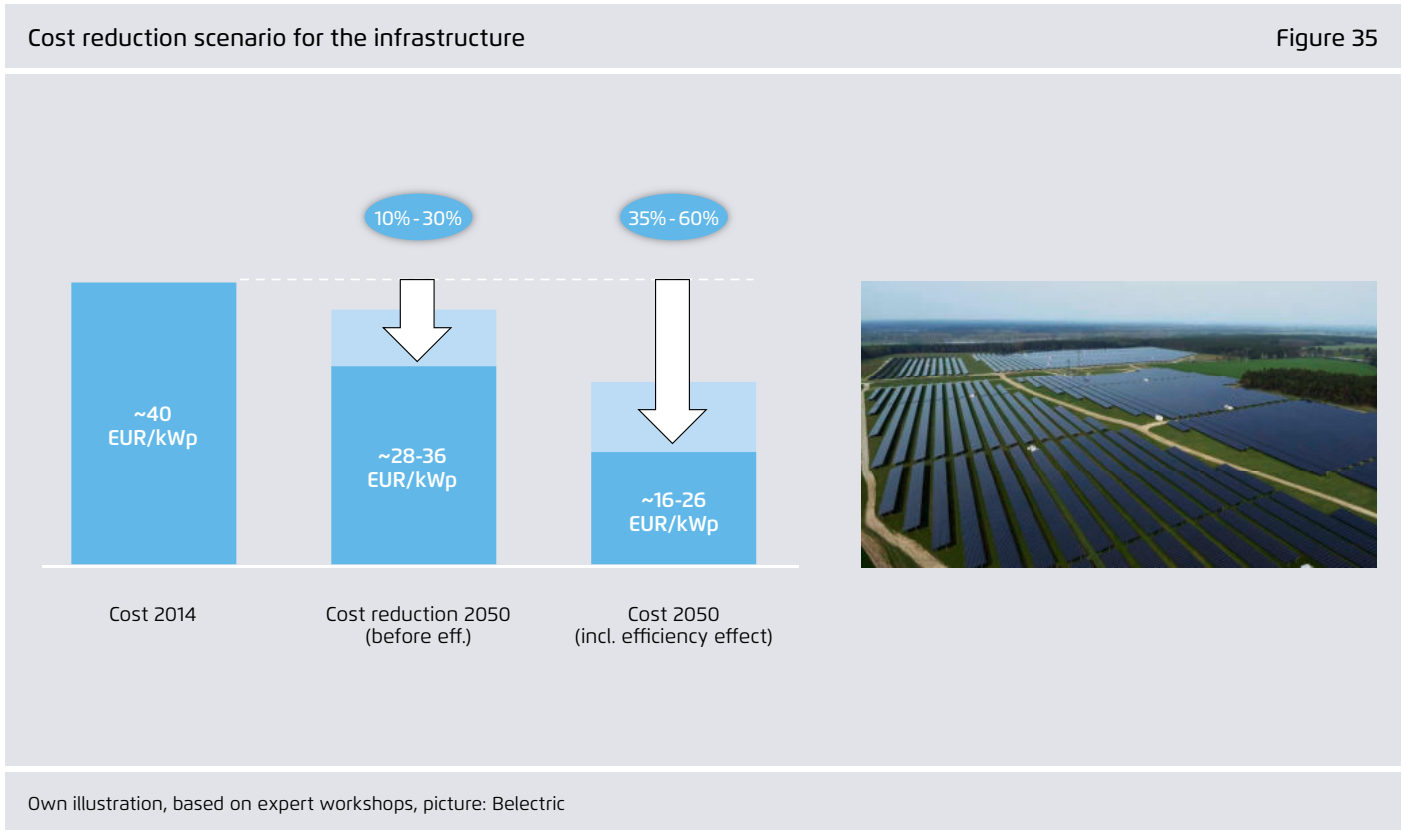
VI Other cost components of ground-mounted PV systems

In this section, the remaining BOS components of planning and documentation, transformers and switch gears are summarised.

Costs for planning and documentation are approx. 35 EUR/kWp today and can be reduced in the future by standardisation and modularisation of PV farms (best case: up to 30 percent). Yet as it includes largely cost of skilled labour, future cost reduction might be as low as 0 percent (worst case). The efficiency impact factor is assumed to be 75 percent because of the large influence of physical and economic parameters (incl. permits) compared to electrical design.

Increasing PV plant size will drive cost reductions for the transformer (today approx. 20 EUR/ kWp) and especially for the switch gear (today approx. 5 EUR/kWp), for which today in many cases significantly overdimensioned systems are applied for smaller PV power plants. Future cost reductions can be expected mainly due to a voltage increase in the

power plant allowing for fewer but more powerful transformers. Since a transformer with double the power costs less than two smaller units, a significant cost saving can be expected. Cost reduction in the transformer is therefore estimated from 20 to 40 percent, for the switch gear from 0 to 50 percent. As the module efficiency does not have any impact on transformers and switch gears, the efficiency impact factor is assumed to be 0 percent.

Total other BOS costs add up to approx. 60 EUR/kWp today and are calculated to range between 29 and 46 EUR/kWp in 2050 (Figure 36).

Appendix 9.5 summarises all assumptions on BOS cost as well as the results in the combination of scenarios.

Cost reduction scenario for the other BOS cost components — Figure 36

7% - 35%

23% - 53%

~60 EUR/kWp

~39-56 EUR/kWp

~29-46 EUR/kWp

Cost 2014

Cost reduction 2050 (before eff.)

Cost 2050 (incl. efficiency effect)

Own illustration, based on expert workshops
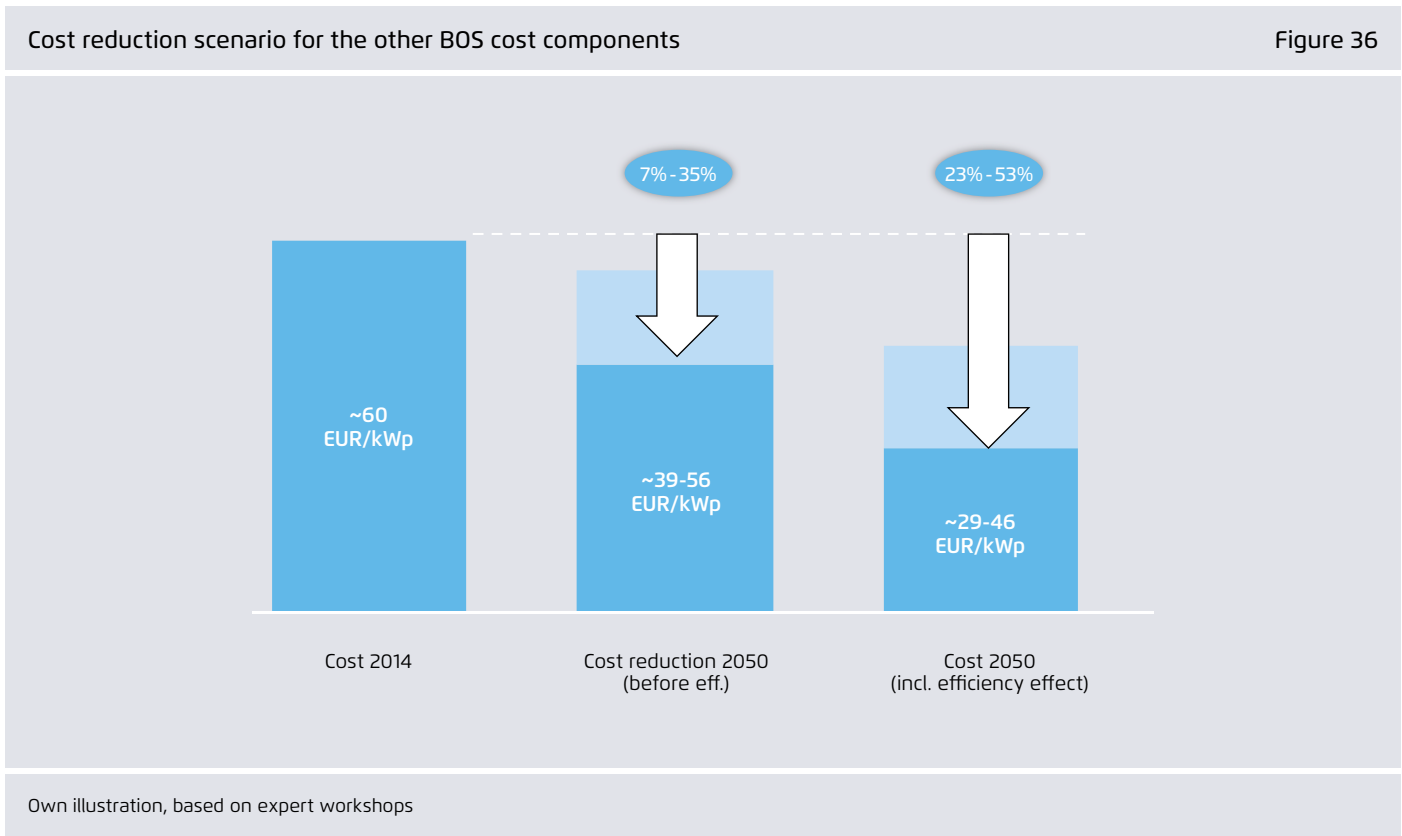
5.4 Summary of BOS cost projection

Having discussed the cost reduction potential of every BOS component in the last section, we now combine all assumptions to get an overall picture of the future BOS costs. Figure 37 shows that the average BOS costs of 340 EUR/kWp in 2014 decline by 39 percent to 210 EUR/kWp when combining all worst-case assumptions and to 120 EUR/kWp when combining the best-case assumptions, representing a 65 percent cost reduction. A closer look at the drivers of the cost reduction in the different scenarios (Appendix 9.5) shows that in the worst-case assumptions, the impact of increasing module efficiency dominates the non-efficiency-related cost reductions. In the combination of all best-case assumptions, the impact of increasing module efficiency is approximately equal to that of other cost reductions.

Summary BOS: Combination of worst-case and best-case assumptions results in a BOS cost range in 2050   Figure 37

Own illustration, based on expert workshops
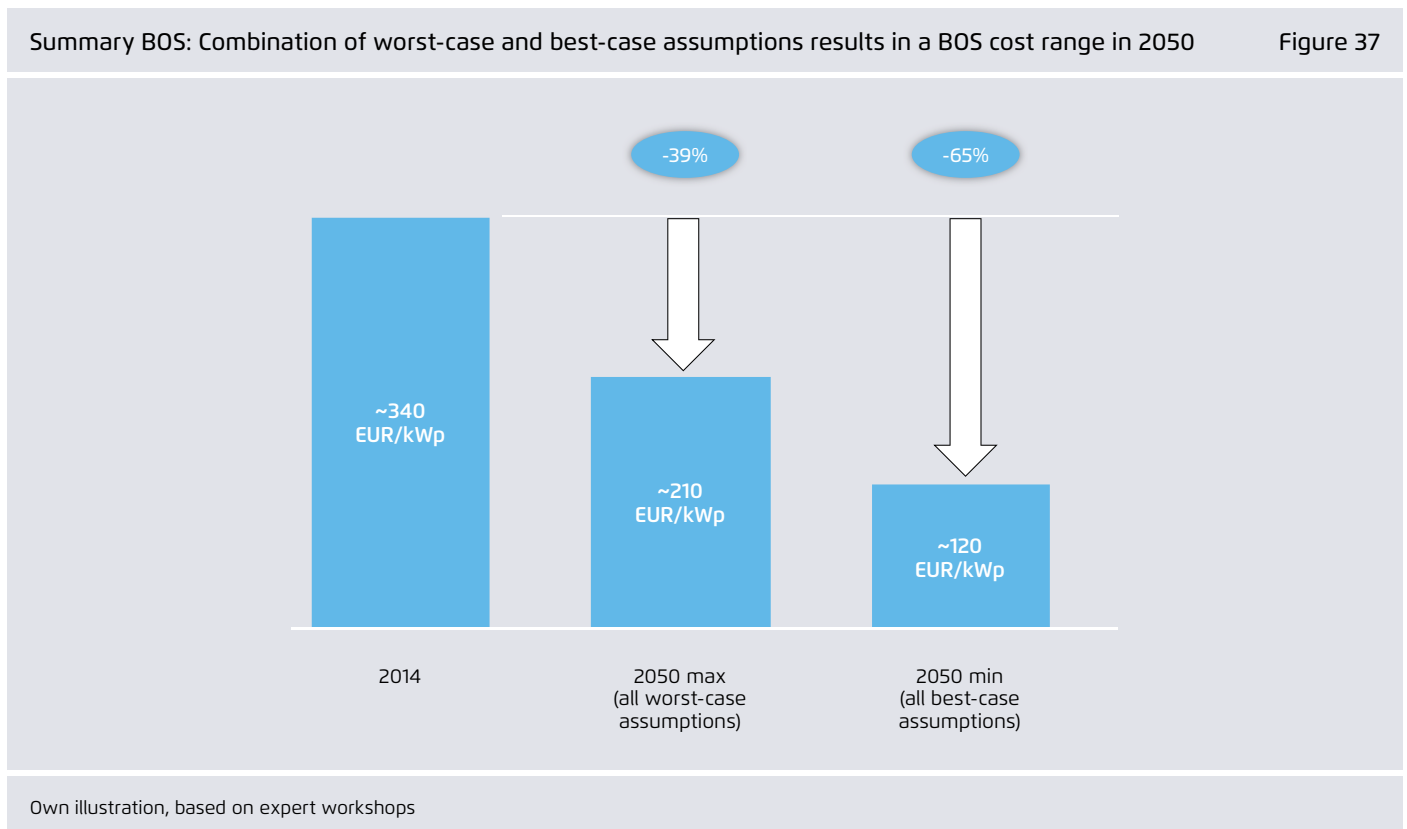
6 System cost projection and LCOE calculation

6.1 Future system prices for utility-scale PV applications

The previous sections discussed the future cost development of each component of a ground-mounted PV system; in the following these components are summarised to describe scenarios of future PV system prices (Figure 38). For the module and inverter, the learning curve approach is applied, based on different market scenarios and the past technology prices. For the BOS, a component-based approach is applied, combining assumptions on minimum and maximum cost reduction potential per component with scenarios of module efficiency to calculate future BOS costs. A further differentiation of BOS cost reduction depending on the market scenarios appears justified but was not considered here due to the large uncertainties involved.

To describe the range of results for different scenarios considered in this analysis, we combine all those assumptions that lead to the lowest system costs and, vice versa, all those leading to the highest system costs. For the scenario above for example, the upper edge of the PV system cost of today is combined with the PV-marked scenario resulting in the lowest production costs of modules until 2050, the lowest learning rate of modules (19 percent) and the minimum cost reduction of the BOS components. With this approach all possible combinations of parameter development are covered. Figure 39 shows the approach and the assumptions for the upper and lower range of the PV system cost projection in 2050.

The above explained approach, with the assumptions of the previous sections, results in a development of PV system costs until 2050 illustrated in Figure 40. It can be observed that the cost will decrease down to approx. 278 – 606 EUR/kWp, in

Overview of methodologies applied to estimate the total system cost in 2050   Figure 38
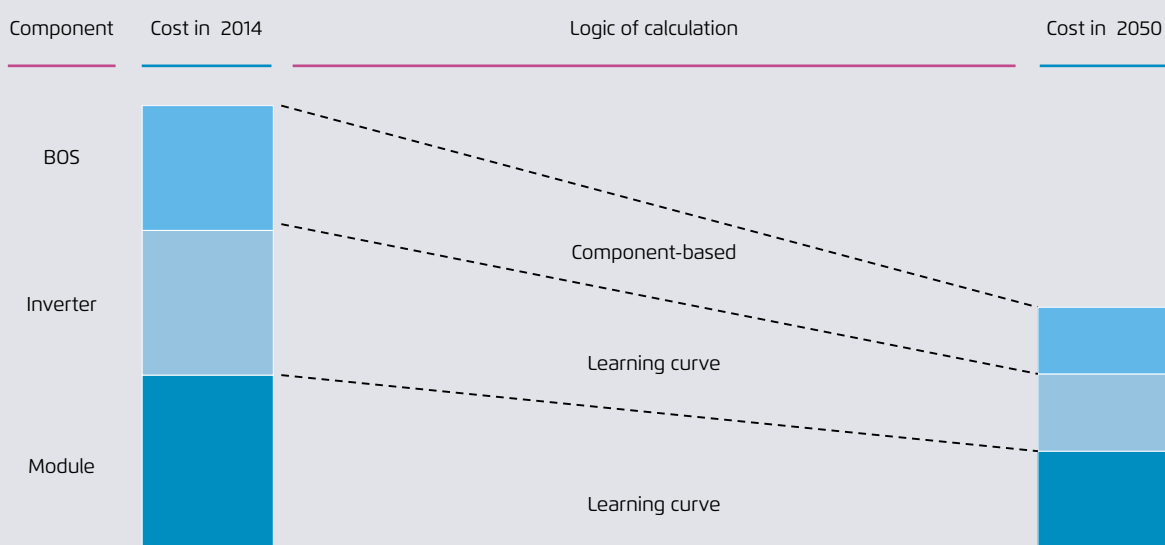
Own illustration

A range of PV system costs in 2050 is derived by combining minimum and maximum assumptions

Figure 39
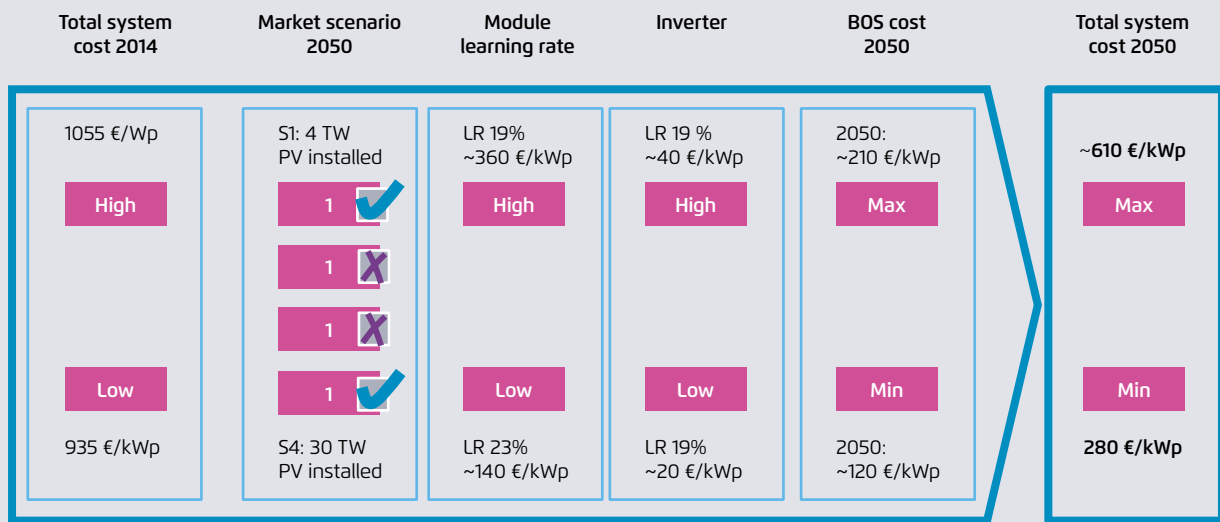
Total system cost 2014	Market scenario 2050	Module learning rate	Inverter	BOS cost 2050	Total system cost 2050
1055 €/Wp	S1: 4 TW PV installed	LR 19% ~360 €/kWp	LR 19 % ~40 €/kWp	2050: ~210 €/kWp	~610 €/kWp
High	**1** ✔	**High**	**High**	**Max**	**Max**
	1 ✗				
	1 ✗				
Low	**1** ✔	**Low**	**Low**	**Min**	**Min**
935 €/kWp	S4: 30 TW PV installed	LR 23% ~140 €/kWp	LR 19% ~20 €/kWp	2050: ~120 €/kWp	280 €/kWp

Own illustration

A range of PV system costs in 2050 is derived by combining minimum and maximum assumptions

Figure 40

2014

~1000 €/kWp

BOS	335
Inverter	110
Module	550

2050

Max

~610 €/kWp

- 206
- 43
- 357

Min

~280 €/kWp

- 117
- 20
- 135
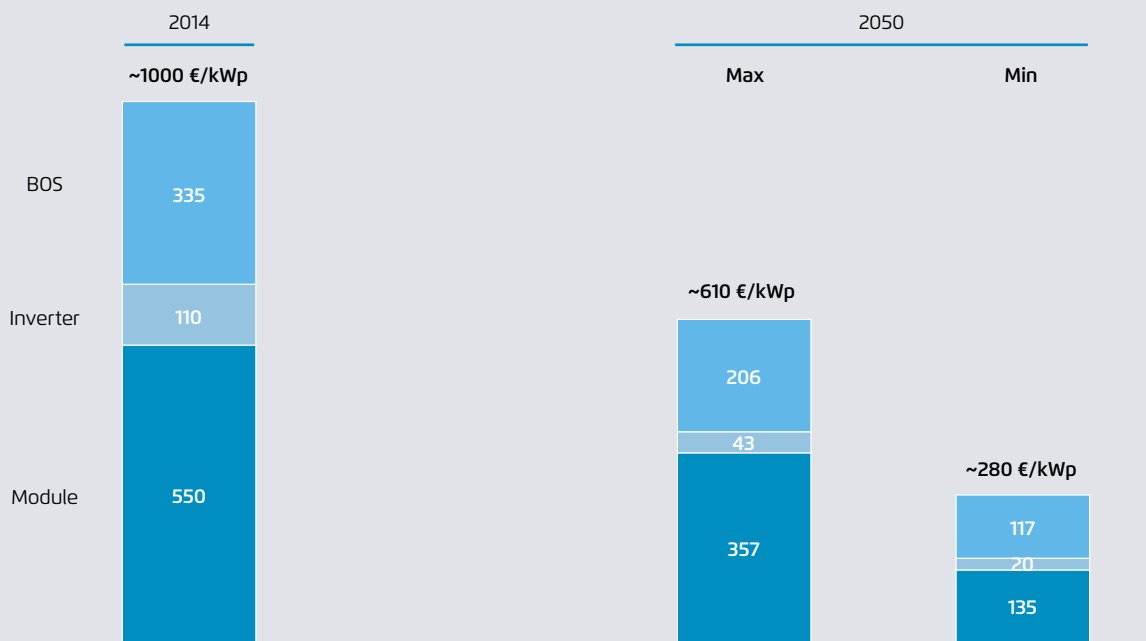
Own illustration

average more than the half of today's costs, as a result of the market development and therefore the learning effects of modules and inverters as well as the efficiency-related cost reduction potential of the other components. The large range of results reflects the large uncertainty of future developments considered here.

A more detailed look at the results of the different market development scenarios and the cost breakdown to the components of module, inverter and BOS is given in Figure 41. Quite remarkably, the differences in resulting system prices vary almost equally within the market development scenarios (variation between 160 and 180 EUR/kWp) and between the market development scenarios (variation of up to 170 EUR/kWp) and the difference between market scenario 3 and the "PV breakthrough" scenario 4 is with approx. 50 EUR/kWp in 2050 relatively small.

Comparing the cost breakdown of the components in scenario four with that of today reveals that the share of BOS of the total system cost is increasing, whereas the share of

modules and inverters diminishes. With around 46 percent of the total system cost, the role of the BOS components is getting more important, whereas in scenario 1 the share of BOS on the total system cost is just rising slightly. Hence a clear trend of the weighting of the components in the total system cost cannot be observed in this analysis.

The development of PV system costs over time is depicted in Figure 42, using the market development scenarios to calculate the cost development of modules and inverters and assuming a linear development of BOS costs. Driven by the logarithmic cost reduction path implied in the learning curve methodology, cost reductions are stronger in the first years. Until 2025, cost reductions of 19 to 36 percent are calculated. This implies that half of the long-term cost reductions expected until 2050 is likely to occur within the next 10 years already.

2050 PV system cost comparison between the different scenarios — Figure 41

Own illustration
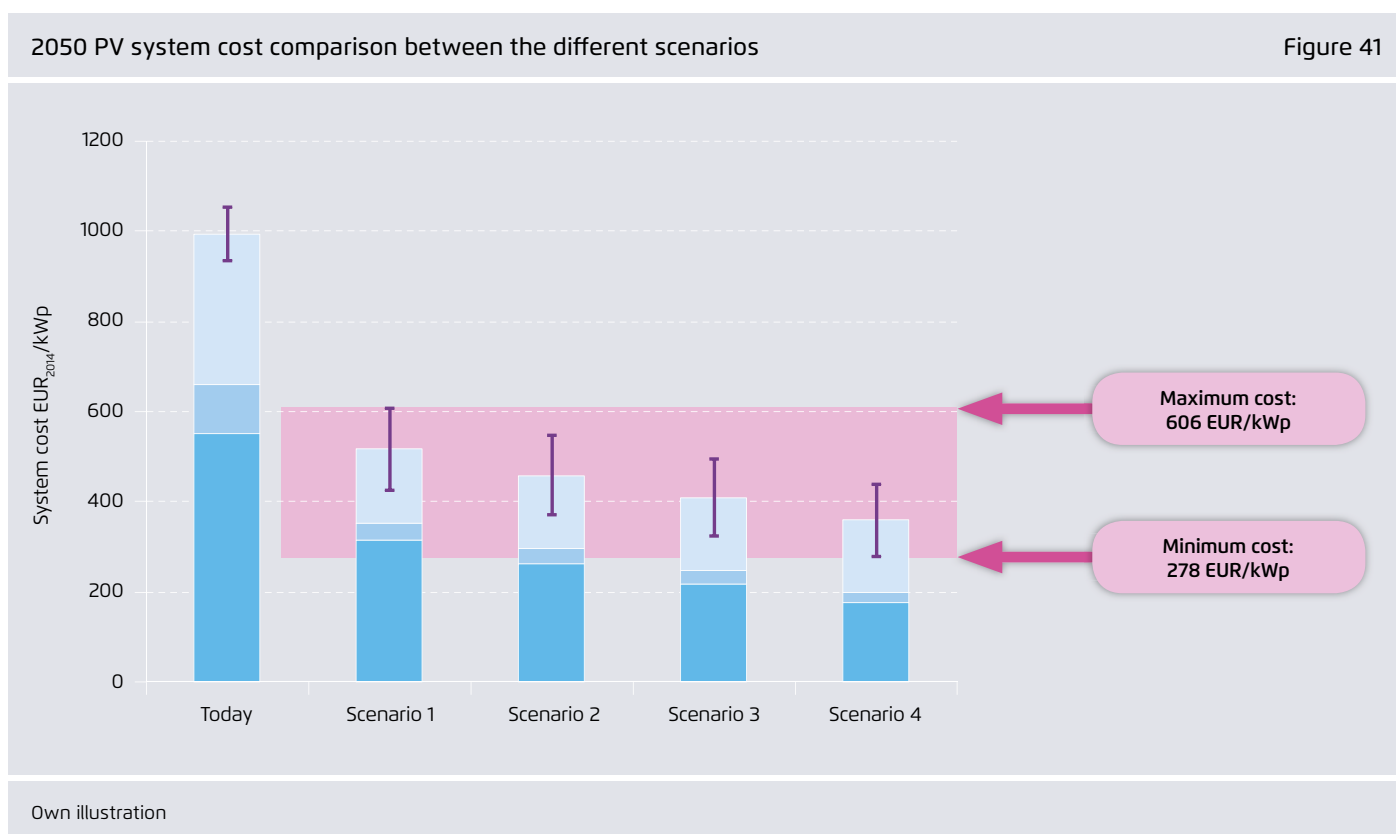
Range of future cost developments in the different scenarios   Figure 42

Own illustration
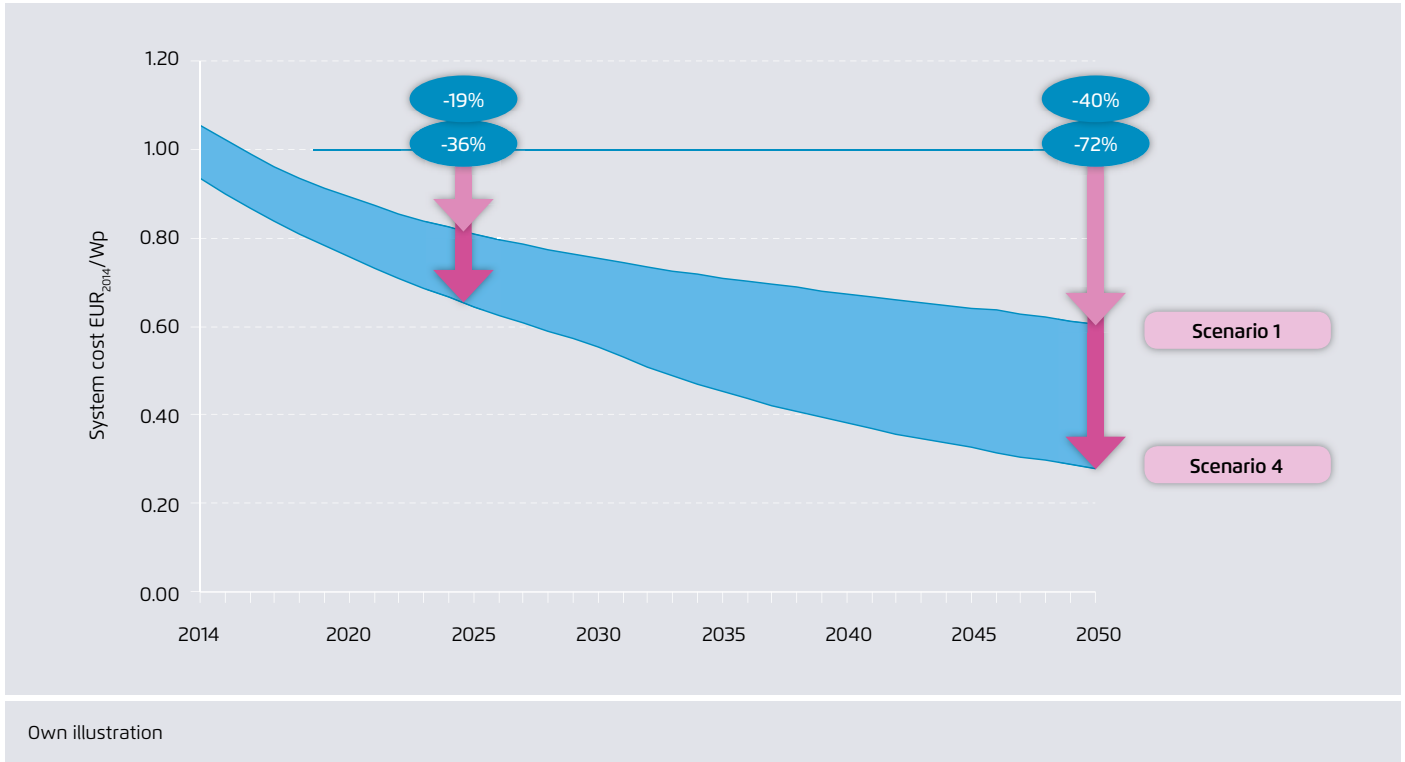
6.2 Methodology explained: Levelised costs of electricity

The method of levelised costs of electricity (LCOE) makes it possible to compare the cost of electricity produced in power plants of different generation and cost structures. It is important to note that this method is an abstraction from reality with the goal of making different sorts of generation plants comparable and does not include other aspects such as the ability to react to the demand for electricity. The method is not suitable for determining the financial feasibility of a specific power plant. For that, a financing calculation must be completed taking into account all revenues and expenditures on the basis of a cash-flow model.

The calculation of the average LCOE is done on the basis of the net present value method, in which the expenses for investment and the payment streams from earnings and expenditures during the plant's lifetime are calculated based on discounting from a shared reference date. The cash values of all expenditures are divided by the cash values of

power generation. Discounting the generation of electricity seems, at first glance, incomprehensible from a physical point of view but is simply a consequence of mathematic transformations. The idea behind it is that the energy generated implicitly corresponds to the earnings from the sale of this energy. The farther these earnings are displaced in the future, the lower their net present value. The LCOE are calculated using the following formula [26]:

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{M_{t,el}}{(1+i)^t}}$$

I_0 Investment expenditures in EUR
A_t Annual total costs (fuels, O&M costs) in EUR in year t
$M_{t,el}$ Produced quantity of electricity in the respective year in kWh
i Real discount rate in%
n Economic operational lifetime in years
t Year of lifetime (1, 2, ...n)

The LCOE calculation is done in real values of the reference year – in this study 2014 (sometimes referred to as constant euros, whereas current euros would be the synonym for nominal values), so all input parameters have to be in real values as well. The reason for that is that projecting the inflation over a long period of time is very difficult and therefore unreliable. This is important to note when comparing LCOE values to feed-in tariffs, which are often fixed in nominal terms without inflation adjustment (as is the case e.g. in Germany) and will therefore be higher, as their value decreases in real terms over the lifetime of a plant.

6.3 Levelised costs of electricity analysis

After we have determined the range of system prices in the different scenarios, we now want to present the LCOE (levelised costs of electricity) in EUR/kWh, a measure widely used to calculate the cost of electricity generation. We use the following assumptions to calculate the LCOE:

→ Discount rate: 5 percent real (~ 7 percent nominal)
→ Operating expenditures (OPEX) in 2014: 20 EUR/kWp
→ Operating expenditures (OPEX) in 2050: 10 EUR/kWp
→ Degradation of solar modules: 0.2 percent p.a.
→ System lifetime in 2014: 25 years
→ System lifetime in 2050: 30 years
→ Inverter replacement after 15 years

Three different locations are considered with the following energy yield at optimal module orientation:

→ Southern Germany: 1190 kWh/kWp (86 percent performance ratio)
→ Southern France: 1380 kWh/kWp (83 percent performance ratio)
→ Southern Spain: 1680 kWh/kWp (81 percent performance ratio)

The GHI (global horizontal irradiation) of the three locations considered ranges from 1200 to 1800 kWh/m²/year. The assumed performance ratios are based on the experience in system monitoring at Fraunhofer ISE. The performance ratio (PR) accounts for losses in the PV system due to electri-

cal wiring, mismatch of modules, inverter and transformer efficiency, soiling, temperature losses, etc. The module name plate power is determined at 25 °C module temperature. With increasing module temperature, the energy output decreases by a certain factor that is determined by the specific module technology (~0.4 – 0.5 percent/K for crystalline silicon). This explains why the assumed performance ratio is lower for systems in southern Spain than in southern Germany, where average temperatures are lower. Typical performance ratios for good PV installations are in the range of 75 to 90 percent, depending on the location. With bifacial solar modules, that are able to utilise light not only from the front, but also from the backside of the module, PV systems can reach higher performance ratios, in some cases even above 100 percent (further explanation in Section 9.2 in the appendix).

In 2014 the LCOE calculated for utility scale PV systems at these locations, combining the assumptions above with the analysis of system cost in the previous sections, range between 5.4 and 8.4 ct$_{EUR}$/kWh (Figure 43). In 2050, the LCOE is calculated to range between 1.8 and 4.4 ct$_{EUR}$/kWh. It is interesting to note, that the differences in LCOE in 2050 are fairly low between the different market scenarios, although the global installed PV capacity differs from about 4,300 GW in scenario 1 to over 30,700 GW in scenario 4.

The LCOE for PV electricity in southern Germany in 2050 is calculated to be in the range of 2.5 to 4.4 ct$_{EUR}$/kWh (Figure 44) with 3.4-4.4 ct$_{EUR}$/kWh even in the most conservative market scenario considered. In southern Spain the range of LCOE in 2050 is calculated to be between 1.8 and 3.1 ct$_{EUR}$/kWh.

Cost of power produced by ground-mounted PV systems in 2050, southern Germany to southern Spain · Figure 43

Range in Germany (south): 2.5 – 4.4 ct/kWh
Range in Spain (south): 1.8 – 3.1 ct/kWh
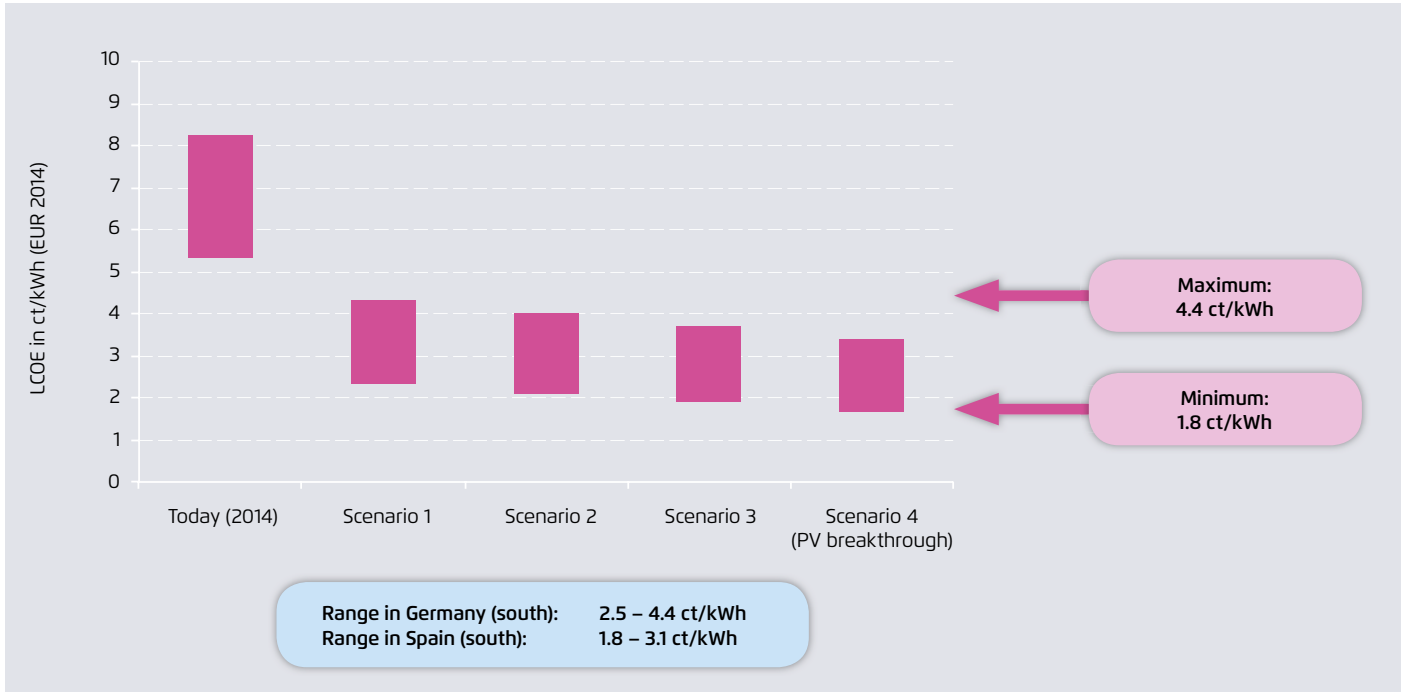
Own illustration

Range of LCOE in the different scenarios for southern Germany in 2050 · Figure 44
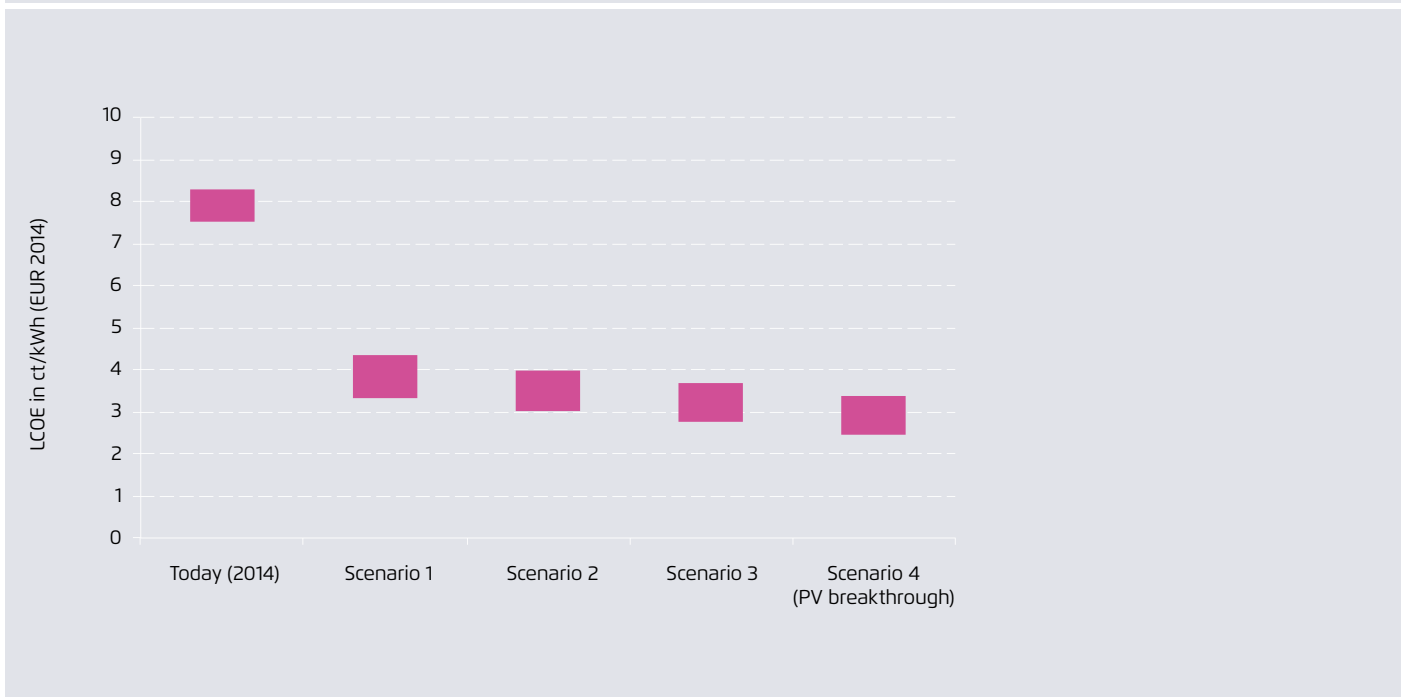
Own illustration

The impact of cost of capital on LCOE

A key point of discussion which evolved around the analysis of LCOE at the expert workshops was the impact of regulatory risk and investment security on the cost of PV generated electricity. It was pointed out by industry experts that the assumption of 5 percent (real) weighted average cost of capital (~7 percent nominal) may be appropriate to describe a situation where a reliable and secure long-term refinancing scheme (i.e. long-term contracts in Germany) allows investors to attract large percentages of long-term debt investment and low-risk premiums on equity capital, reducing the overall cost of capital of a project. Yet in other situations, regulatory or political uncertainty would lead to significantly higher risk profiles and increase cost of capital.

The result of a sensitivity analysis on the impact of the cost of capital is illustrated in Figure 45. As an example, the resulting cost for producing PV power in southern Spain is calculated, assuming 5, 7.5 and 10 percent WACC and is compared to the cost for producing PV power in southern Germany, using the standard assumption of 5 percent WACC.

The increase of cost of capital from 5 to 7.5 percent results in an increase in LCOE from 1.8 to 3.14 ct_{EUR}/kWh to a range of 2.17 to 3.95 ct_{EUR}/kWh. An even higher cost of capital of 10 percent, representing rather a very high assumption on investment risk perception of a PV power plant, could even increase the cost to 2.60 – 4.90 ct_{EUR}/kWh, slightly higher LCOE than in the case of Germany at a cost of capital of 5 percent.

This sensitivity analysis confirms the impression from industry experts that cost of capital is very significant for the LCOE of PV systems, and shows that it can be as important as the level of irradiation.

Sensitivity analysis on the cost of capital	Figure 45

Own illustration
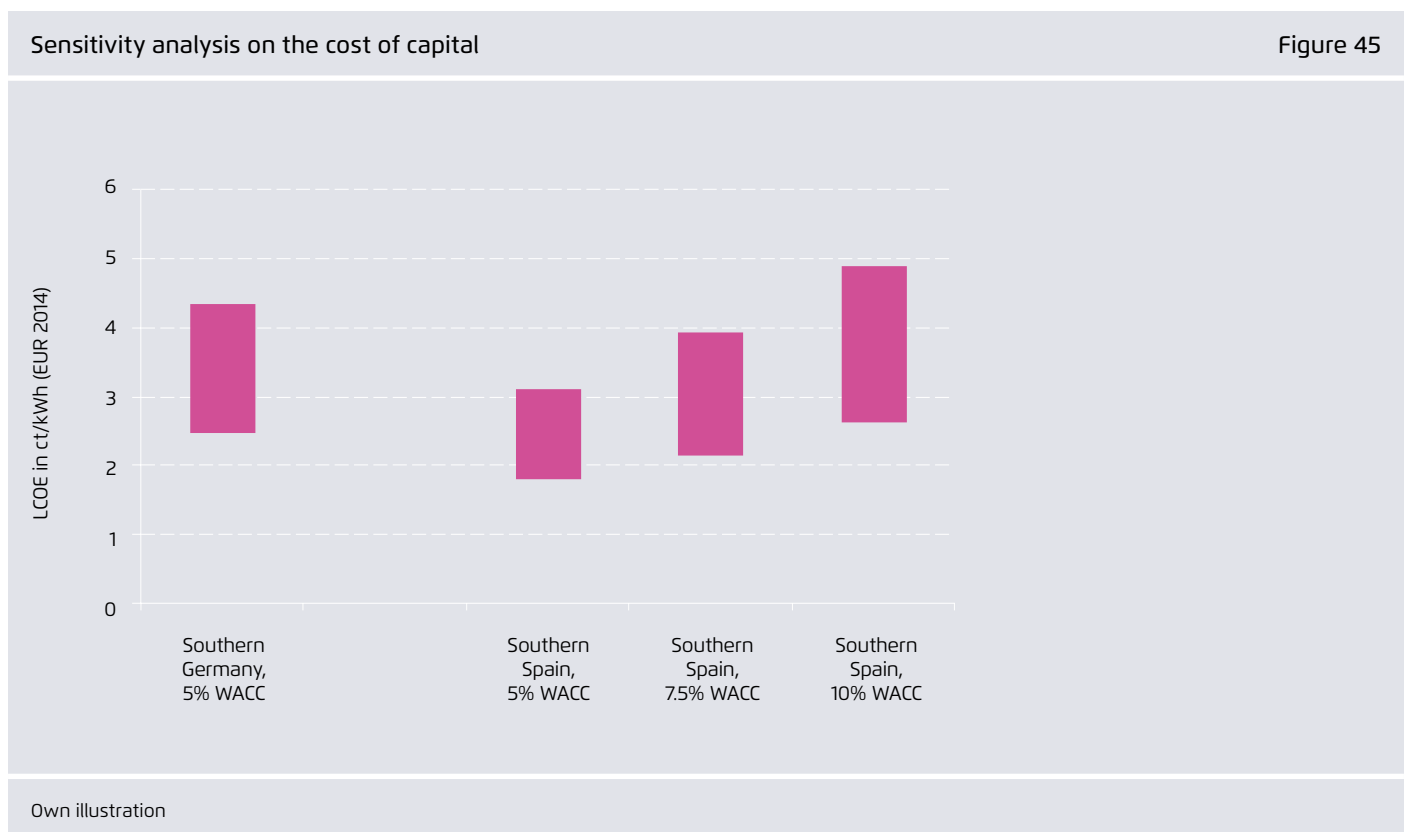
7 Discussion of results

The results of this study describe the current cost for large ground-mounted PV systems as well as a range of long-term cost developments that seem likely from today's point of view. In view of the developments of PV technology and cost over the last couple of years, it seems especially important to critically review such an analysis.

Discussion: Current cost of PV

Both the initial suggestions and the final cost assumptions for a representative solar PV power plant were controversially discussed by experts. Several experts have pointed out that significantly lower system cost of approximately 700 EUR/kW are achieved in different regions, incl. Turkey and China, across the world already today. Public auctioning of power purchase agreements in countries such as Brazil, Uruguay, India and Dubai resulted in power purchase agreements of between 5–8 ct$_{EUR}$/kWh, which supports this argument.

In order to remain consistent with the approach of taking a solar PV system installed in Germany in 2014 as a reference, including the likely lower cost of finance and operations, we used the more conservative estimations based on own research. We are aware that this may represent a conservative figure and might need to be revisited within only a few years.

Discussion: Future technology and cost development

Our analysis builds only on the most established technology of crystalline silicon PV as well as advancements within this technology that are already today known as technically possible. The developments during the last years, as well as recent developments such as in the field of Perovskite solar cells show that technological breakthrough in other PV technologies is far from impossible. Further research is required to further assess the likelihood of such a breakthrough as well as possible implications.

Discussion: PV market development

We considered different scenarios of future global PV market developments with the intention of covering the range of likely developments both in most pessimistic and optimistic cases. We did not include a scenario with declining market volumes over a period of several years, as such a scenario appeared to be highly unlikely in view of current market trends including in relatively new markets such as China and India. Further research is needed to analyse the interaction between development of cost and market, including the competitive interaction with competing power generation technologies.

Discussion: Cost of finance

The insight raised by industry experts that cost of finance has a significant effect on the cost of producing power from solar PV was confirmed in a sensitivity analysis that varied the weighted average cost of capital. This result clearly points to the need for further research on the drivers of cost of capital in PV projects across the world and especially on the impact of policy-making on cost of capital.

8   LCOE calculations for selected countries

The key drivers for the LCOE from large scale solar photovoltaic power plants are the amount of power than can be harvested by a solar photovoltaic system (depending primarily on the solar irradiation) and the capital cost (depending primarily on the financial and regulatory environment). In the following section, we present a number of example calculations which specify the range of future LCOE of solar power for a number of countries and for different cost of capital.

In the following calculations it is assumed that cost for building and operating a large scale photovoltaic power plant are equal in different parts of the world. Estimations regarding full load hours are based on a recent publication

[27] using the range of full load hours described per country while not considering the 10 percent of suitable area with the lowest full load hours per country.

In reality, the solar power production at a specific site may be higher or lower than the range of full load hours depicted here, and cost for specific components may differ, especially in countries with a little developed market for solar photovoltaic installation.

The excel-based calculation tool which allows a calculation of LCOE for other countries, as well as for own assumptions on different parameters is available at www.agora-energiewende.org/pv-lcoe

LCOE Argentina (750 - 1550 kWh/kWp p.a.); WACC between 5% and 10%   Figure 46

LCOE Australia (1050 - 1850 kWh/kWp p.a.); WACC between 5% and 10%   Figure 47

Own illustration

## LCOE Brazil (1150 - 1800 kWh/kWp p.a.); WACC between 5% and 10% — Figure 48
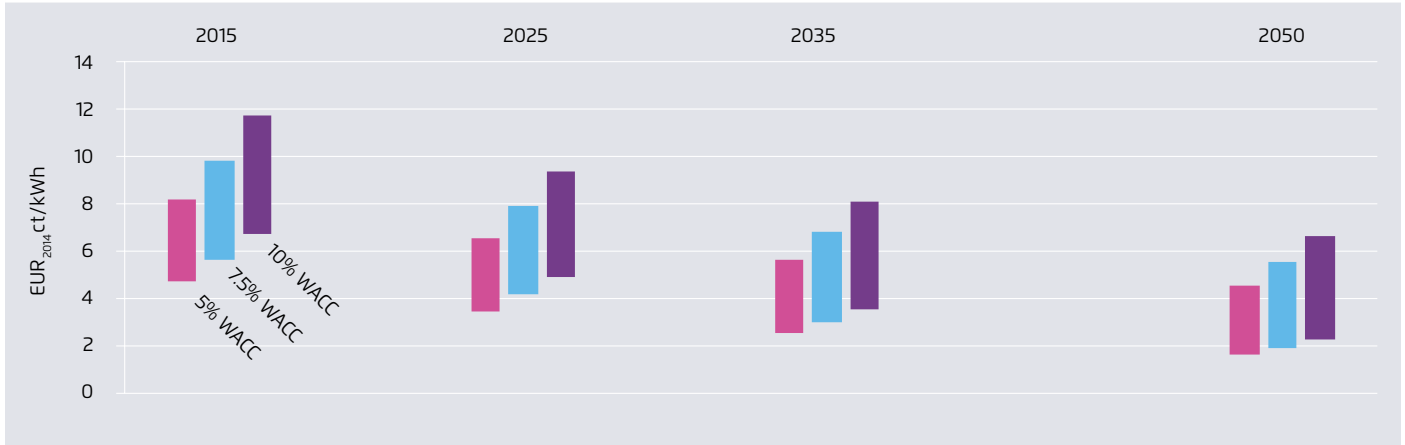
LCOE Canada (900 - 1450 kWh/kWp p.a.); WACC between 5% and 10% — Figure 49

LCOE China (1150 - 1750 kWh/kWp p.a.); WACC between 5% and 10% — Figure 50
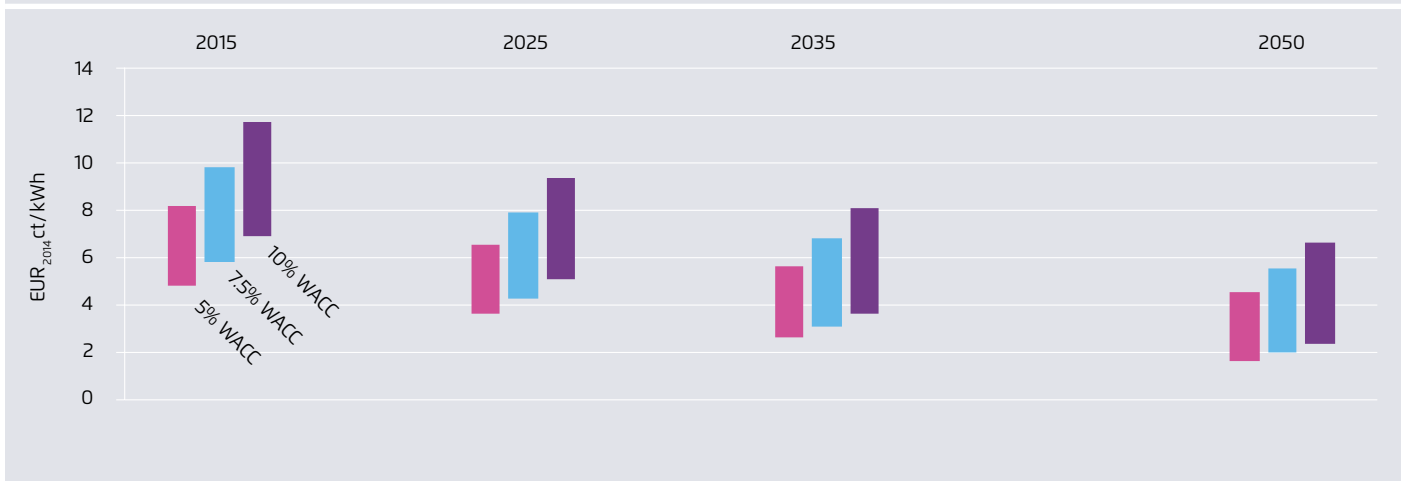
Own illustration

LCOE France (1000 – 1550 kWh/kWp p.a.); WACC between 5% and 10%   Figure 51

2015   2025   2035   2050

EUR$_{2014}$ct/kWh

10% WACC
7.5% WACC
5% WACC
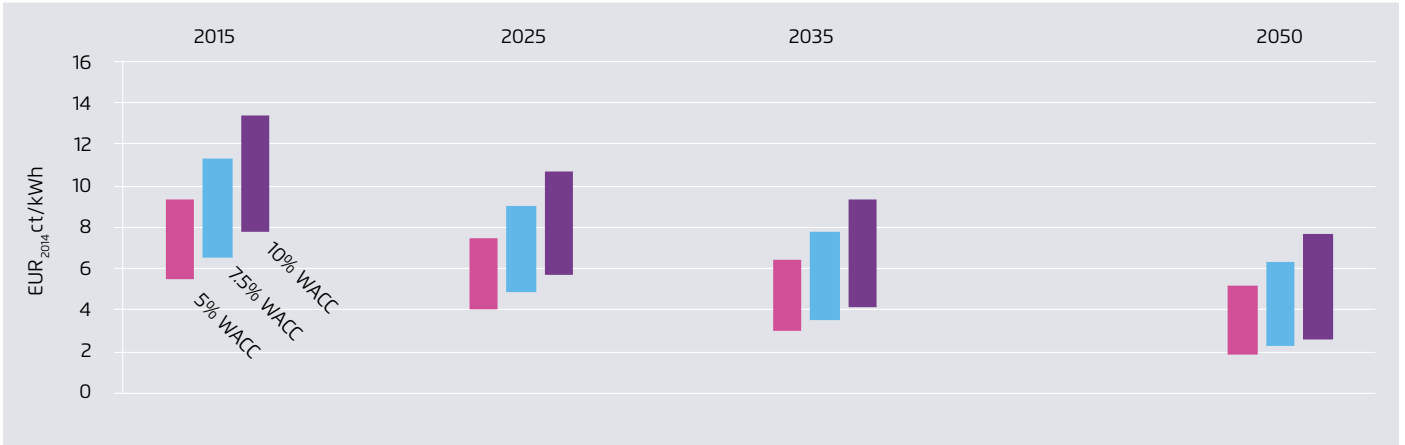
LCOE India (1400 – 1850 kWh/kWp p.a.); WACC between 5% and 10%   Figure 52

2015   2025   2035   2050

EUR$_{2014}$ct/kWh

10% WACC
7.5% WACC
5% WACC
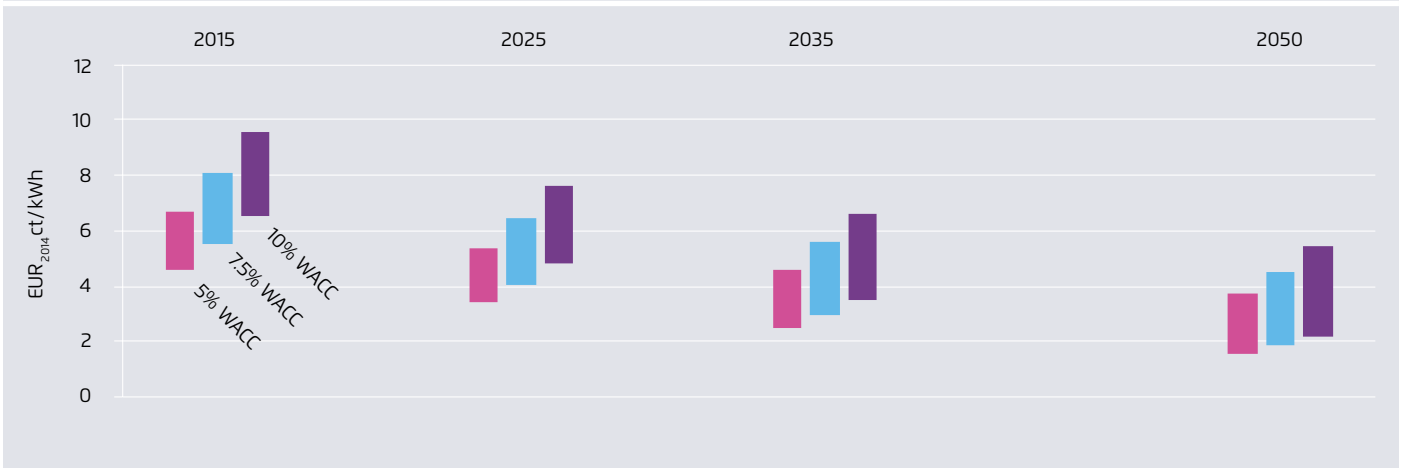
LCOE Korea, South (1300 – 1350 kWh/kWp p.a.); WACC between 5% and 10%   Figure 53

2015   2025   2035   2050

EUR$_{2014}$ct/kWh

10% WACC
7.5% WACC
5% WACC
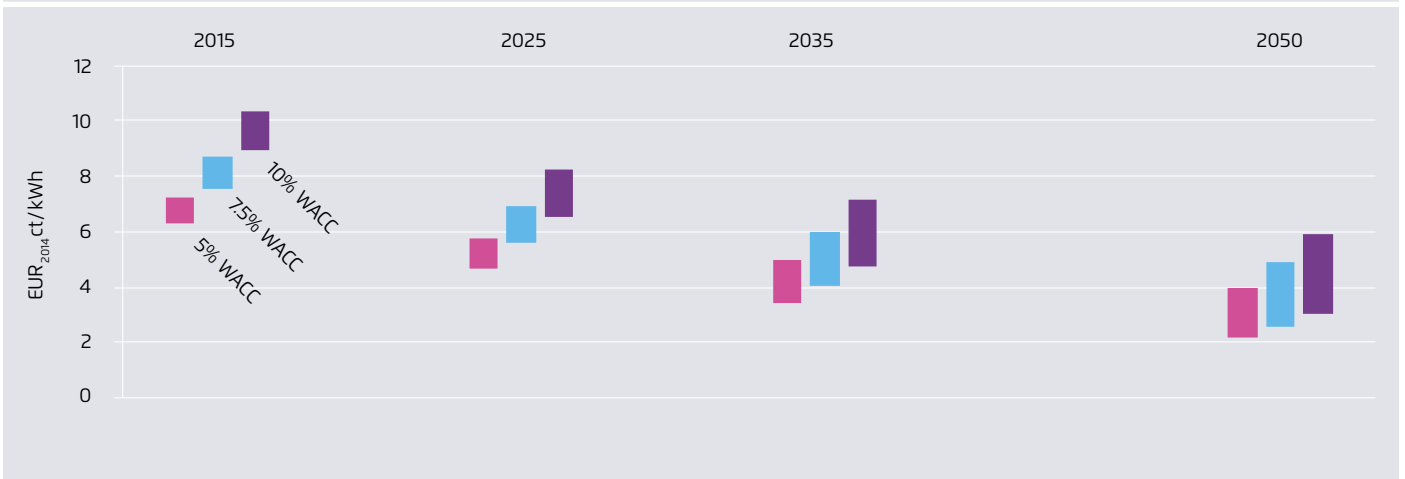
Own illustration

LCOE Morrocco (1500 - 1850 kWh/kWp p.a.); WACC between 5% and 10%   Figure 54
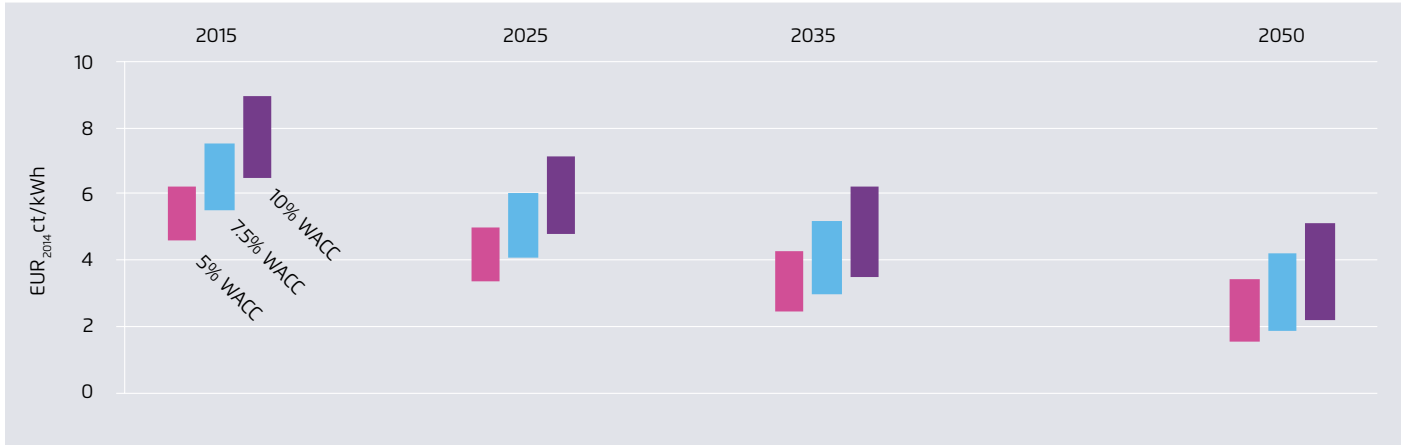
LCOE Russia (850 - 1550 kWh/kWp p.a.); WACC between 5% and 10%   Figure 55

LCOE Saudi Arabia (1550 - 1900 kWh/kWp p.a.); WACC between 5% and 10%   Figure 56
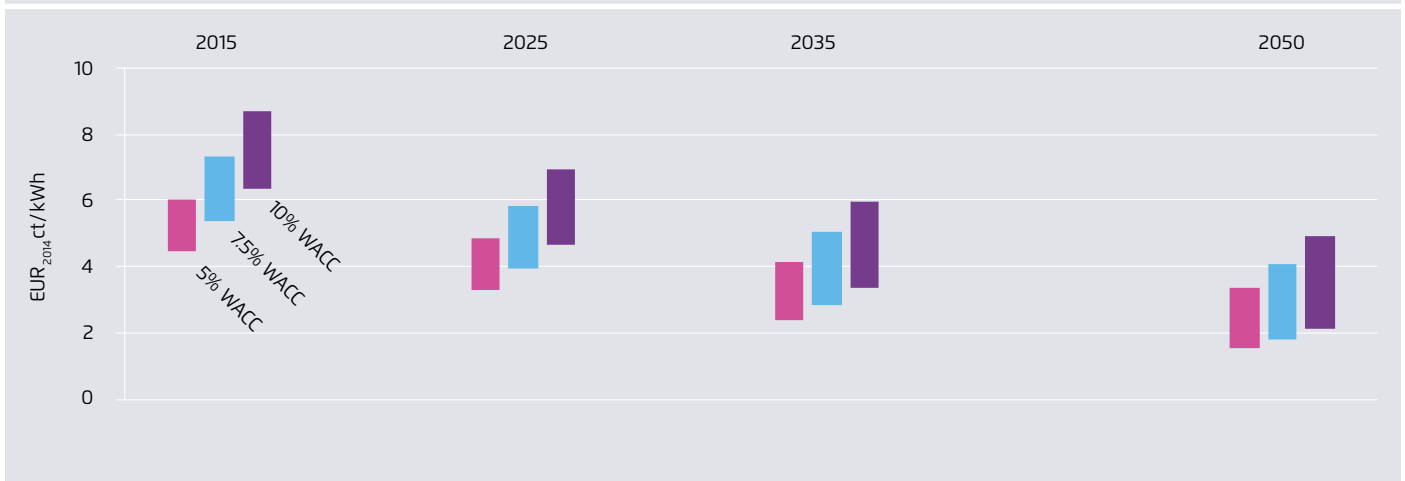
Own illustration

LCOE South Africa (1000 - 1300 kWh/kWp p.a.); WACC between 5% and 10%   Figure 57
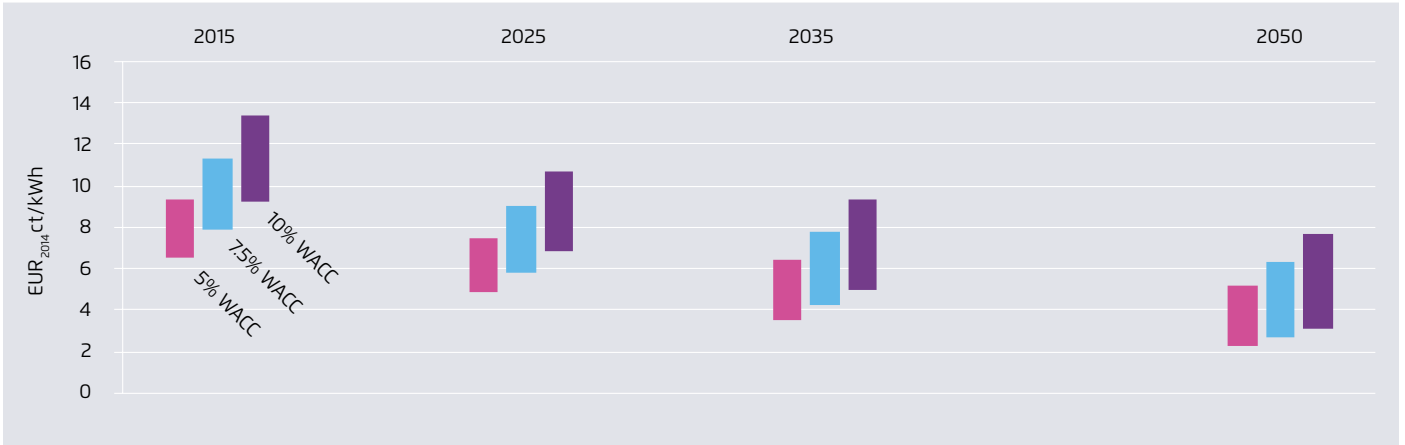
LCOE Spain (1350 - 1900 kWh/kWp p.a.); WACC between 5% and 10%   Figure 58
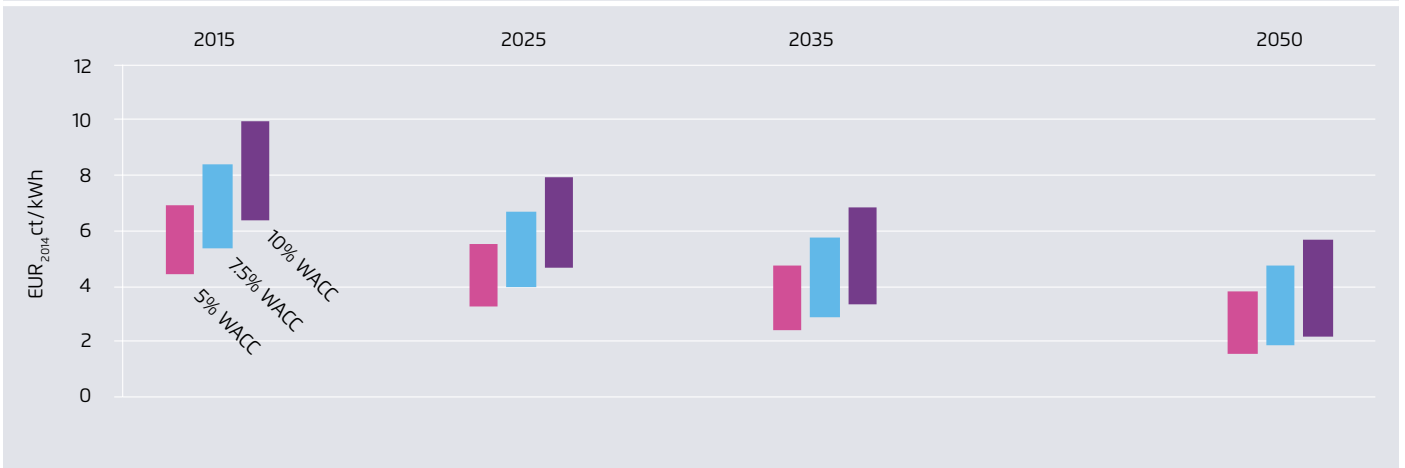
LCOE Thailand (1350 - 1600 kWh/kWp p.a.); WACC between 5% and 10%   Figure 59
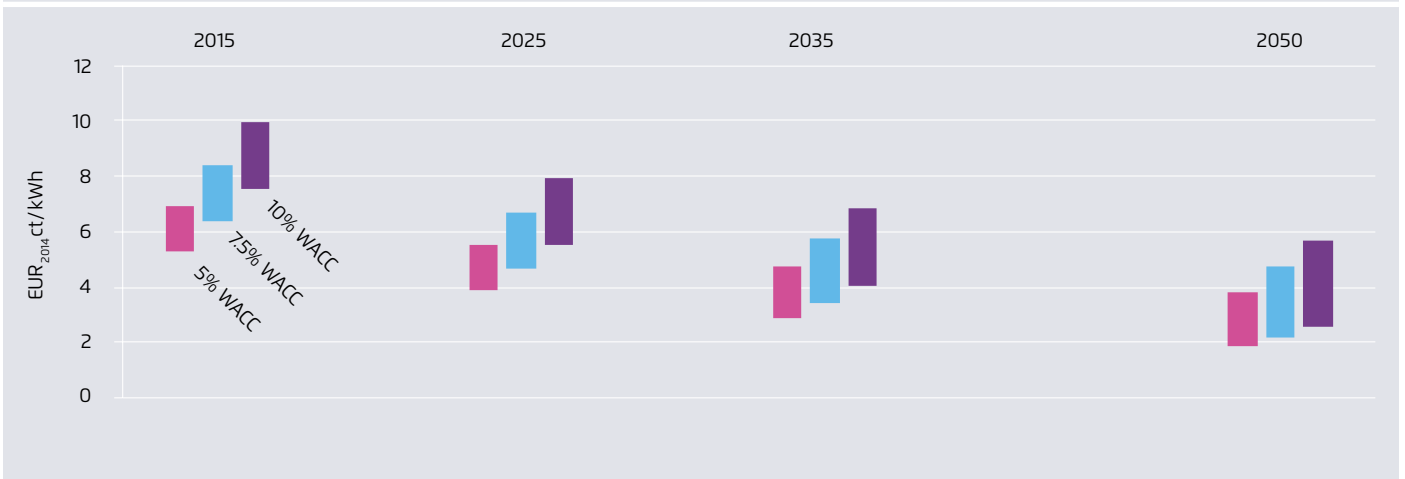
Own illustration

LCOE Turkey (1350 - 1750 kWh/kWp p.a.); WACC between 5% and 10%   Figure 60
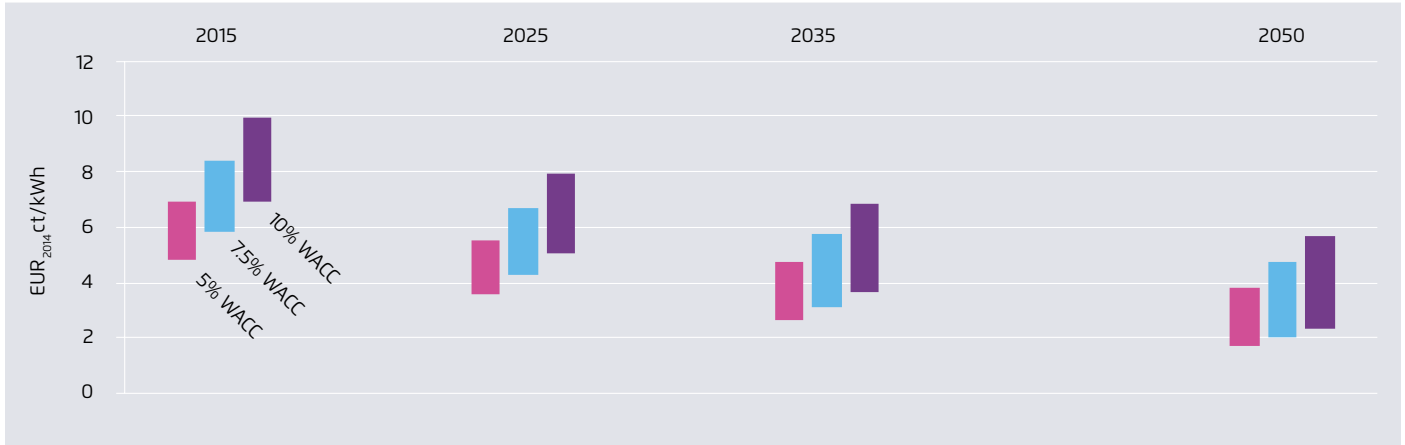
LCOE Uganda (1450 - 1750 kWh/kWp p.a.); WACC between 5% and 10%   Figure 61
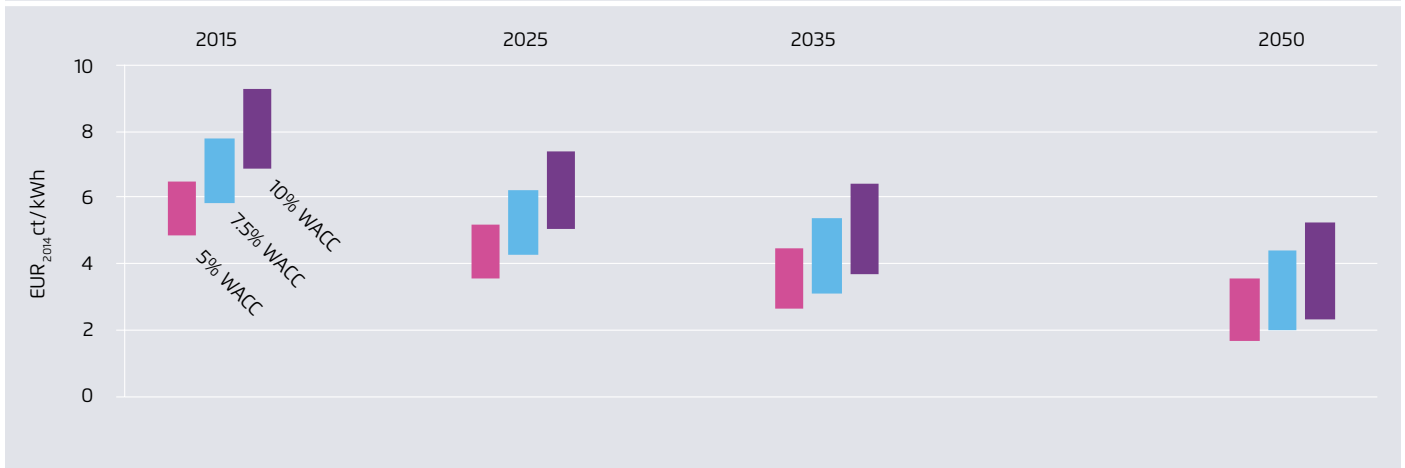
LCOE United Kingdom (800 - 1150 kWh/kWp p.a.); WACC between 5% and 10%   Figure 62
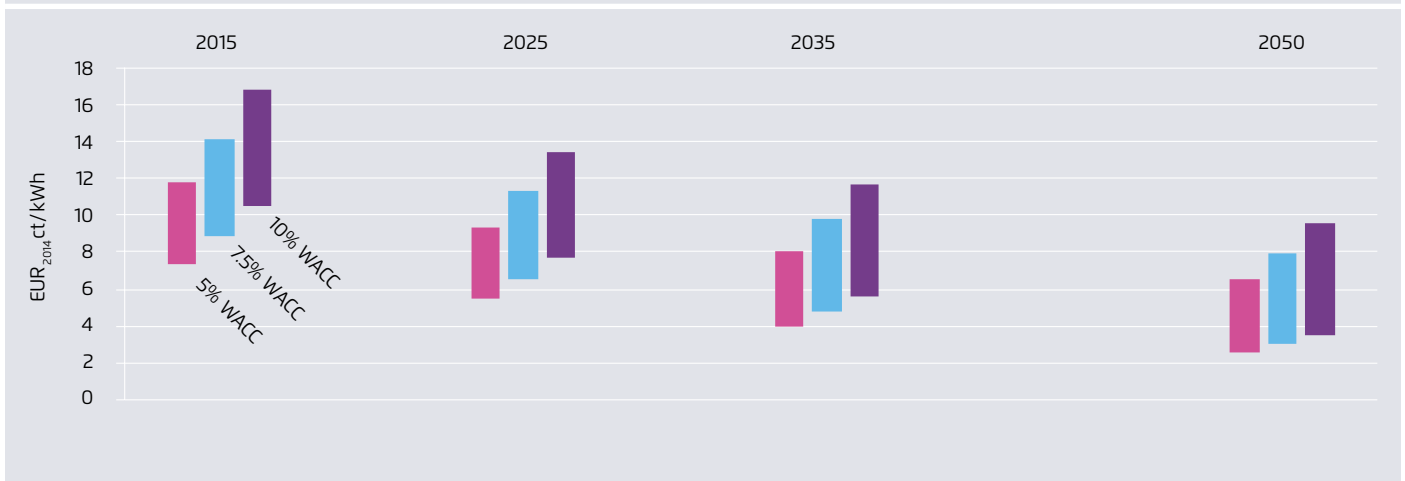
Own illustration

LCOE United States (1350 - 1950 kWh/kWp p.a.); WACC between 5% and 10%   Figure 63
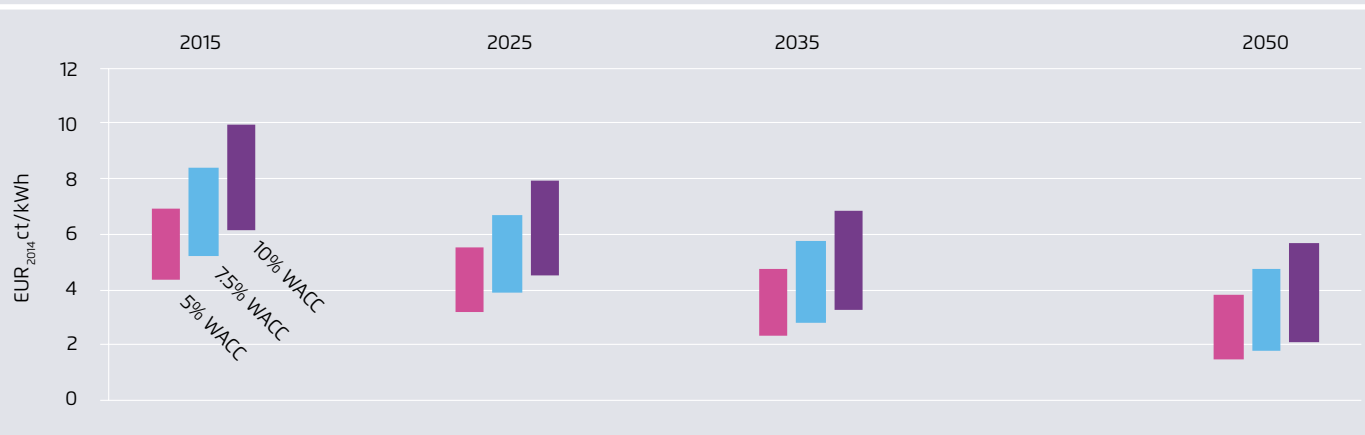
Own illustration

Levelized cost of electricity of large scale solar PV in selected countries, 2015 to 2050, at different cost of capital   Table 5

	LCOE, in EUR₂₀₁₄ct/kWh																							
Year	2015						2025						2035						2050					
WACC	5%		7,5%		10%		5%		7,5%		10%		5%		7,5%		10%		5%		7,5%		10%	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Argentina	5,5	12,5	6,6	15,1	7,8	17,9	4,1	10,0	4,9	12,1	5,7	14,3	3,0	8,6	3,5	10,4	4,1	12,4	1,9	6,9	2,2	8,5	2,6	10,2
Australia	4,6	8,9	5,5	10,8	6,5	12,8	3,4	7,1	4,1	8,6	4,8	10,2	2,5	6,1	3,0	7,4	3,5	8,9	1,6	4,9	1,9	6,1	2,2	7,3
Brazil	4,7	8,2	5,7	9,8	6,7	11,7	3,5	6,5	4,2	7,9	4,9	9,3	2,6	5,6	3,0	6,8	3,6	8,1	1,6	4,5	1,9	5,5	2,3	6,7
Canada	5,8	10,4	7,0	12,6	8,3	14,9	4,3	8,3	5,2	10,0	6,1	11,9	3,2	7,2	3,8	8,7	4,4	10,3	2,0	5,8	2,4	7,1	2,8	8,5
China	4,8	8,2	5,8	9,8	6,9	11,7	3,6	6,5	4,3	7,9	5,1	9,3	2,6	5,6	3,1	6,8	3,7	8,1	1,7	4,5	2,0	5,5	2,3	6,7
France	5,5	9,4	6,6	11,3	7,8	13,4	4,1	7,5	4,9	9,0	5,7	10,7	3,0	6,4	3,5	7,8	4,1	9,3	1,9	5,2	2,2	6,4	2,6	7,7
India	4,6	6,7	5,5	8,1	6,5	9,6	3,4	5,4	4,1	6,5	4,8	7,7	2,5	4,6	3,0	5,6	3,5	6,6	1,6	3,7	1,9	4,5	2,2	5,5
Korea, South	6,3	7,2	7,5	8,7	8,9	10,3	4,7	5,8	5,6	7,0	6,6	8,3	3,4	5,0	4,1	6,0	4,8	7,1	2,2	4,0	2,6	4,9	3,0	5,9
Morocco	4,6	6,3	5,5	7,5	6,5	9,0	3,4	5,0	4,1	6,0	4,8	7,2	2,5	4,3	3,0	5,2	3,5	6,2	1,6	3,5	1,9	4,2	2,2	5,1
Russia	5,5	11,0	6,6	13,3	7,8	15,8	4,1	8,8	4,9	10,6	5,7	12,6	3,0	7,6	3,5	9,2	4,1	10,9	1,9	6,1	2,2	7,5	2,6	9,0
Saudi Arabia	4,5	6,1	5,4	7,3	6,3	8,7	3,3	4,8	4,0	5,8	4,7	6,9	2,4	4,2	2,9	5,0	3,4	6,0	1,5	3,3	1,8	4,1	2,1	4,9
South Africa	6,5	9,4	7,8	11,3	9,3	13,4	4,8	7,5	5,8	9,0	6,8	10,7	3,5	6,4	4,2	7,8	4,9	9,3	2,3	5,2	2,7	6,4	3,1	7,7
Spain	4,5	6,9	5,4	8,4	6,3	9,9	3,3	5,6	4,0	6,7	4,7	7,9	2,4	4,8	2,9	5,8	3,4	6,9	1,5	3,8	1,8	4,7	2,1	5,7
Thailand	5,3	6,9	6,4	8,4	7,5	9,9	3,9	5,6	4,7	6,7	5,5	7,9	2,9	4,8	3,4	5,8	4,0	6,9	1,8	3,8	2,2	4,7	2,5	5,7
Turkey	4,8	6,9	5,8	8,4	6,9	9,9	3,6	5,6	4,3	6,7	5,1	7,9	2,6	4,8	3,1	5,8	3,7	6,9	1,7	3,8	2,0	4,7	2,3	5,7
Uganda	4,8	6,5	5,8	7,8	6,9	9,3	3,6	5,2	4,3	6,2	5,1	7,4	2,6	4,4	3,1	5,4	3,7	6,4	1,7	3,6	2,0	4,4	2,3	5,3
United Kingdom	7,4	11,7	8,9	14,1	10,5	16,8	5,5	9,4	6,5	11,3	7,7	13,4	4,0	8,1	4,8	9,8	5,6	11,6	2,6	6,5	3,0	8,0	3,5	9,6
United States	4,3	6,9	5,2	8,4	6,2	9,9	3,2	5,6	3,9	6,7	4,5	7,9	2,4	4,8	2,8	5,8	3,3	6,9	1,5	3,8	1,8	4,7	2,1	5,7

Own calculations

9   Appendix

9.1   Summary of results in tables

Investment cost of solar PV power plants until 2050, range within scenarios   Table 6

Investment cost solar PV (turnkey cost) EUR(2014)/kWp Min-Max	2014	2020	2025	2030	2035	2040	2045	2050
Scenario 1	935 - 1055	768 - 892	680 - 810	615 - 753	562 - 710	516 - 674	473 - 642	425 - 606
Scenario 2	935 - 1055	762 - 885	664 - 792	592 - 728	536 - 681	475 - 629	420 - 585	371 - 546
Scenario 3	935 - 1055	759 - 882	653 - 780	574 - 707	494 - 636	427 - 577	372 - 531	324 - 493
Scenario 4	935 - 1055	757 - 879	645 - 771	553 - 685	452 - 590	381 - 525	326 - 478	278 - 440
Total range scenario 1-4	935 - 1055	757 - 892	645 - 810	553 - 753	452 - 710	381 - 674	326 - 642	278 - 606

Investment cost of solar PV power plants until 2050, average values in scenarios   Table 7

Investment cost solar PV (turnkey cost) EUR(2014)/kWp Average value	2014	2020	2025	2030	2035	2040	2045	2050
Scenario 1	995	830	745	684	636	595	558	516
Scenario 2	995	824	728	660	608	552	502	458
Scenario 3	995	820	716	640	565	502	452	409
Scenario 4	995	818	708	619	521	453	402	359
Average value scenario 1-4	995	823	724	651	583	526	479	436

Other cost parameters of solar PV power plants   Table 8

Other cost parameter solar PV	2014	2020	2025	2030	2035	2040	2045	2050
Lifetime, years	25							30
WACC, %	5%	5%	5%	5%	5%	5%	5%	5%
Operating cost per year, EUR(2014)/y/kW	20							10

Power output per surface in different scenarios of module efficiency development until 2050   Table 9

Power output per surface, kWp/m2	2014	2020	2025	2030	2035	2040	2045	2050
Efficiency scenario 1	0,15							0,24
Efficiency scenario 2	0,15							0,3
Efficiency scenario 3	0,15							0,35
Average value scenario 1-4	0,15							0,30

Own calculations

9.2 Technology outlook: Bifacial solar modules

Bifacial PV modules are able to utilise light not only from the front, like classical PV modules, but also from the backside. Hence the area-related efficiency can be increased in a power plant, when these modules generate additional electricity from the light reflected from the ground to the backside of the modules. This additional electricity yield is determined by two factors: First, by the backside efficiency of the bifacial solar module, which can be more than 90 percent of the frontside efficiency, and secondly, by the share of irradiation reaching the backside of the module. The latter is determined by the technical design of the solar system (shading of the backside should be minimised) and the reflectivity of the ground. A typical application for bifacial solar modules would be a tilted system on a light-coloured flat roof, but it could also be applied in ground-mounted systems, preferably in deserts with sand of high reflectivity. For darker grounds the installation of a special reflection foil might be an alternative.

Additional energy yields in the range of 10 to 20 percent are realistic with the bifacial module technology depending on the system design. For individual cases, additional yields up to 30 percent seem possible with optimised system design and particularly good reflectivity. It is important to note that the additional energy yield of bifacial PV modules is typically not reflected in the rated power of the module, which considers only the frontside power, or only part of the additional power from the backside. Therefore the bifacial solar systems can reach performance ratios of up to 105 percent, whereas typical systems with standard modules have performance ratios in the range of 80 to 90 percent. This has to be considered when calculating the LCOE of a bifacial solar system.

Another possible application for bifacial solar modules would be the vertical installation in east-west direction which shifts the production peak from noon to the morning and afternoon hours. First estimates show that the total yield of such systems could be close to that of south facing systems, but with advantages regarding market value and system integration in energy systems with a high PV share.

9.3 Market development scenarios

Installed and produced capacity, scenario 1	Figure 64

Scenario 1: 13% of GG, 4.3 TW PV in 2050
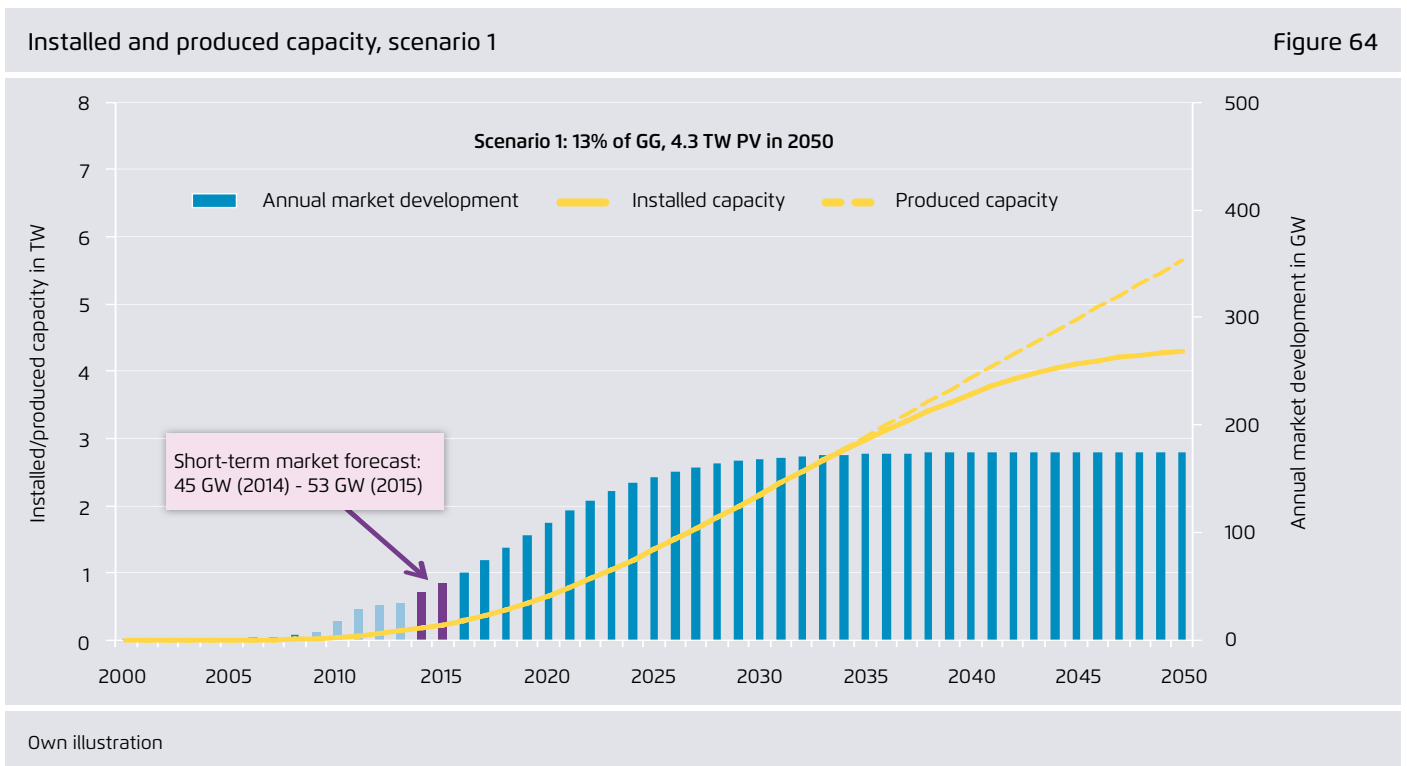
Own illustration

Installed and produced capacity, scenario 2 — Figure 65

Scenario 2: 24% of GG, 7.9 TW PV in 2050

Short-term market forecast:
45 GW (2014) - 53 GW (2015)

Annual market development — Installed capacity --- Produced capacity
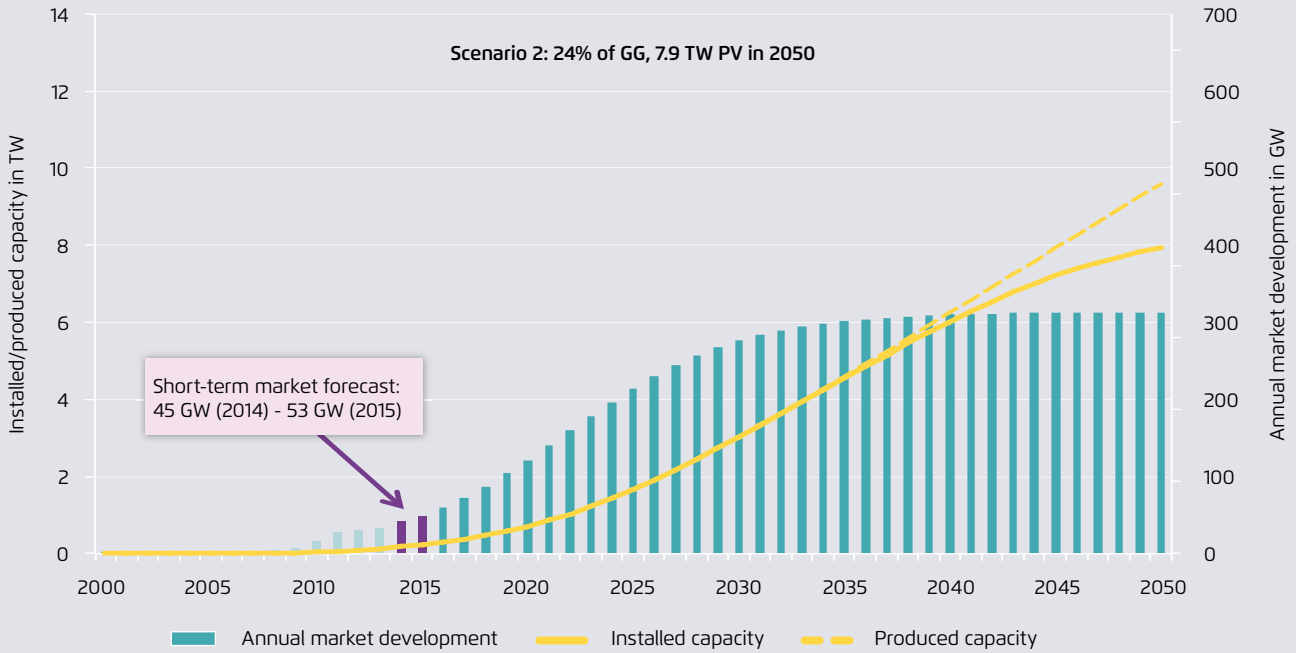
Own illustration

Installed and produced capacity, scenario 3 — Figure 66

Scenario 3: 44% of GG, 14.8 TW PV in 2050

Short-term market forecast:
45 GW (2014) - 53 GW (2015)

Annual market development — Installed capacity --- Produced capacity
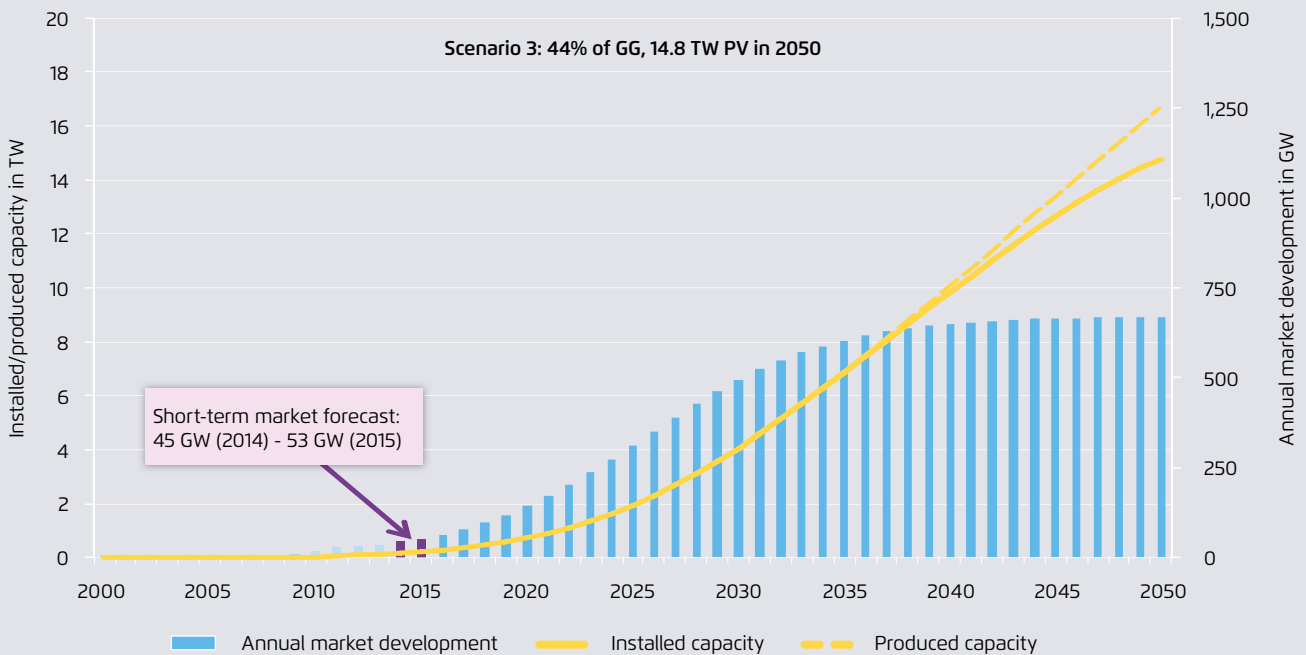
Own illustration

Installed and produced capacity, scenario 4   **Figure 67**

Scenario 4: 40% of GG with fossil fuel shift, 30.7 TW PV in 2050

Short-term market forecast:
45 GW (2014) - 53 GW (2015)

Annual market development — Installed capacity — — Produced capacity
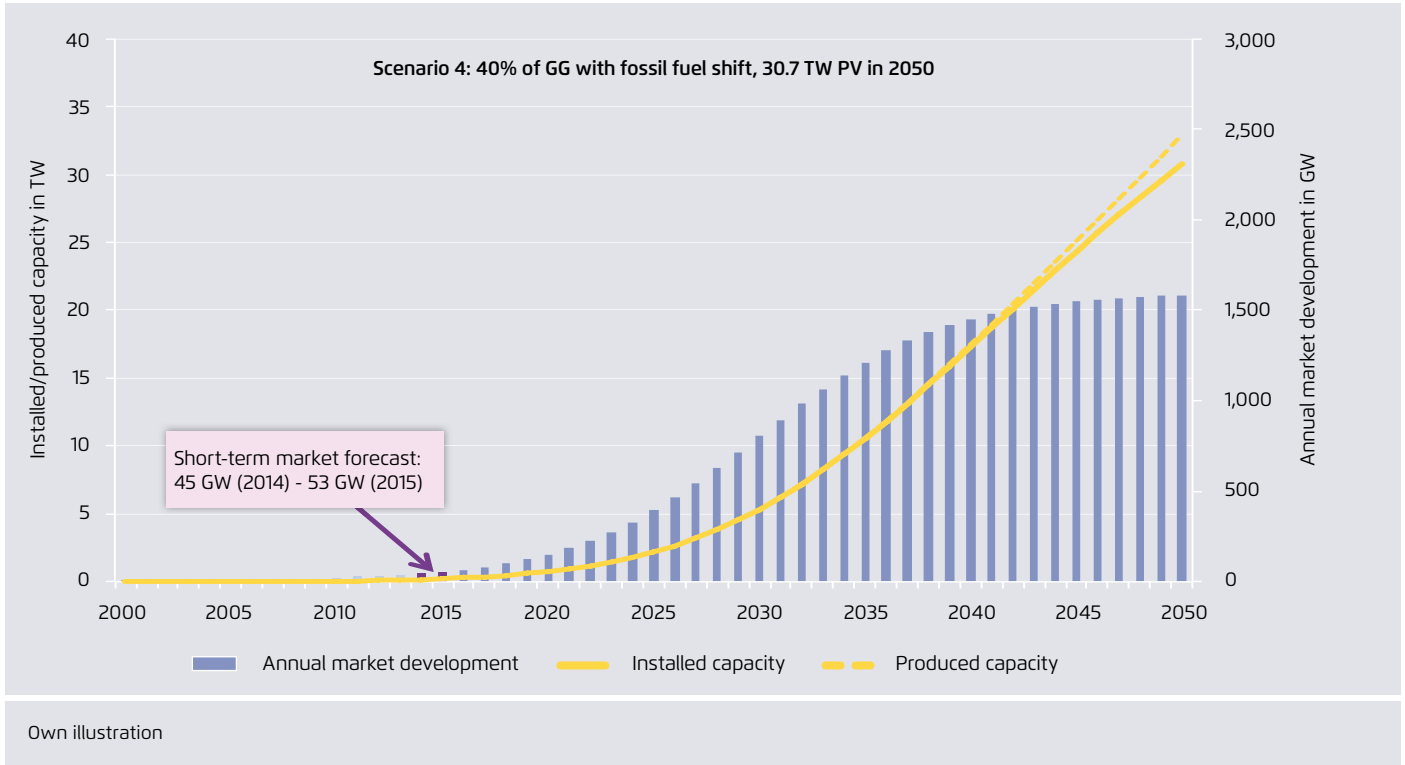
Own illustration

9.4 System cost scenarios

PV system cost, scenario 1   **Figure 68**

Scenario 1 (5% CAGR, S-curve)

BOS
Inverter
Modules
System
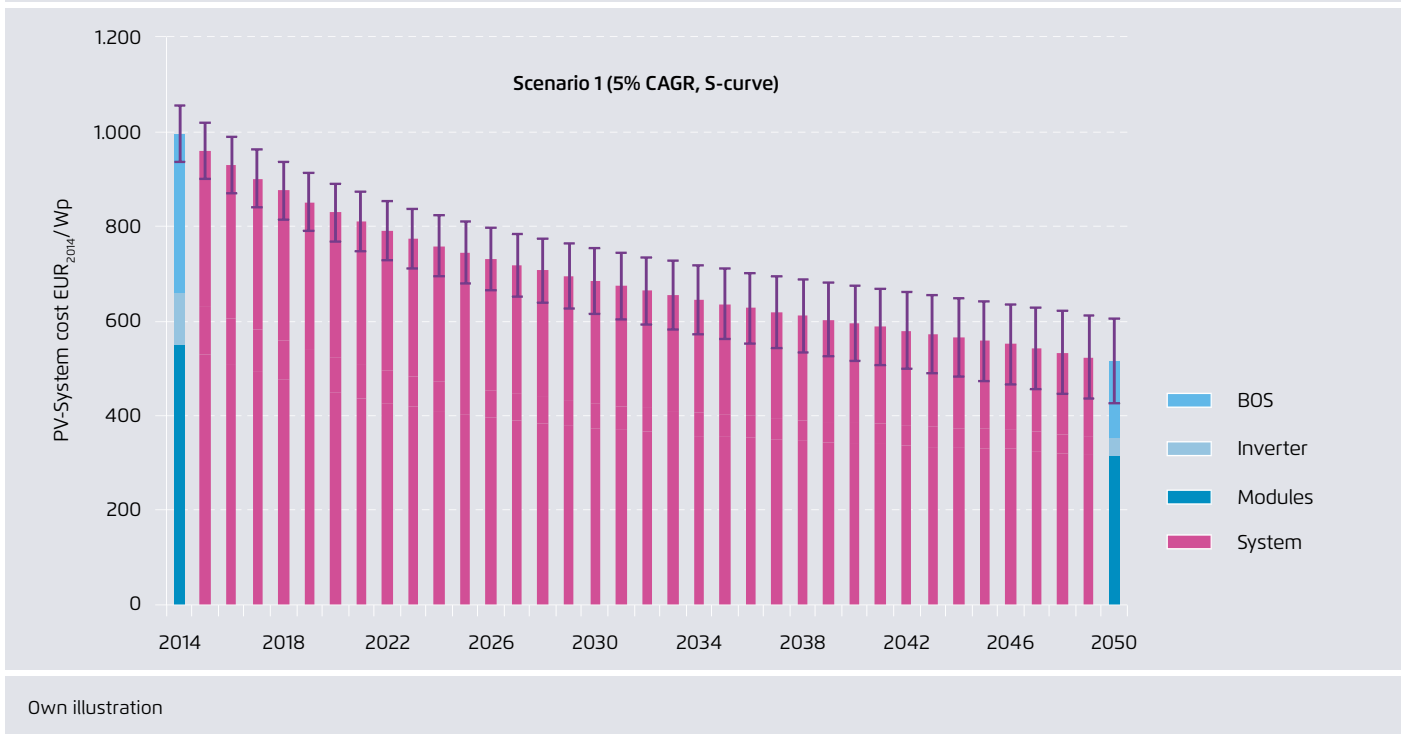
Own illustration

PV system cost, scenario 2   Figure 69

Scenario 2 (7.5% CAGR, S-curve)

Legend:
- BOS
- Inverter
- Modules
- System

y-axis: PV-System cost EUR_{2014}/Wp
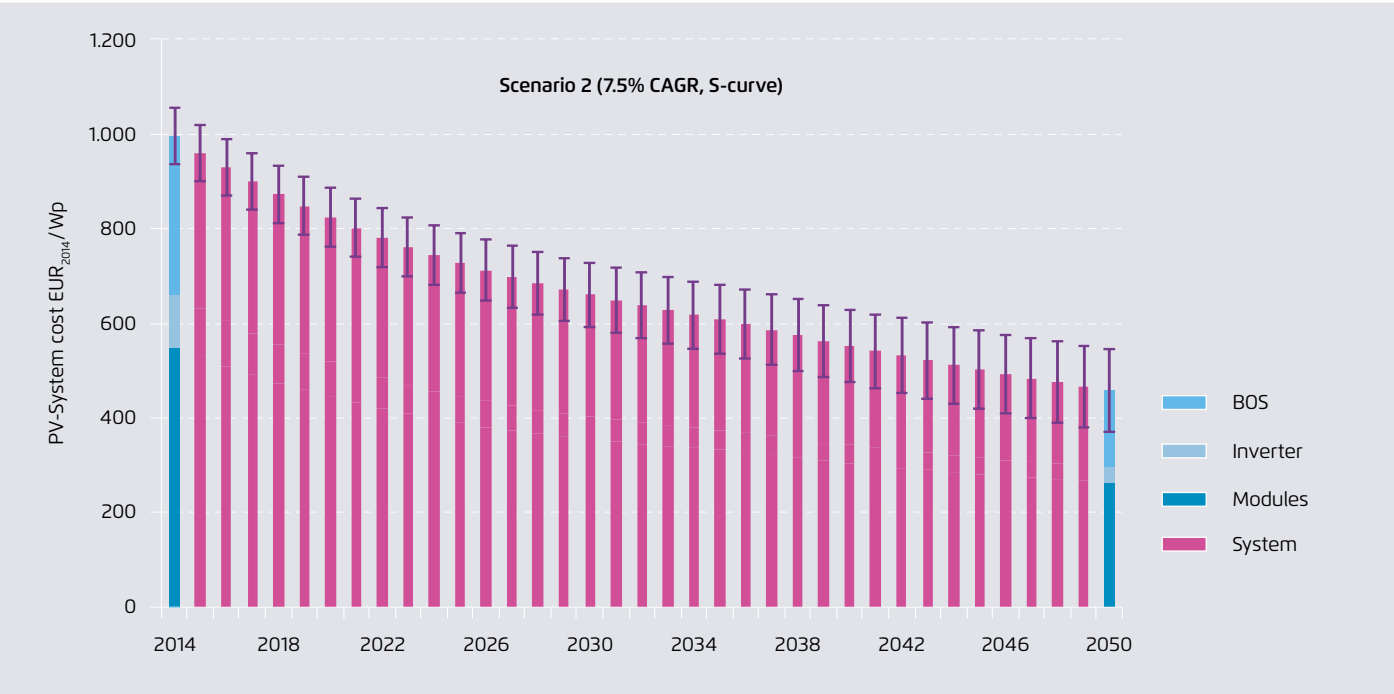
Own illustration

PV system cost, scenario 3   Figure 70

Scenario 3 (10% CAGR, S-Curve)

Legend:
- BOS
- Inverter
- Modules
- System

y-axis: PV-System cost EUR_{2014}/Wp

Own illustration

PV system cost, scenario 4 (PV breakthrough)   Figure 71
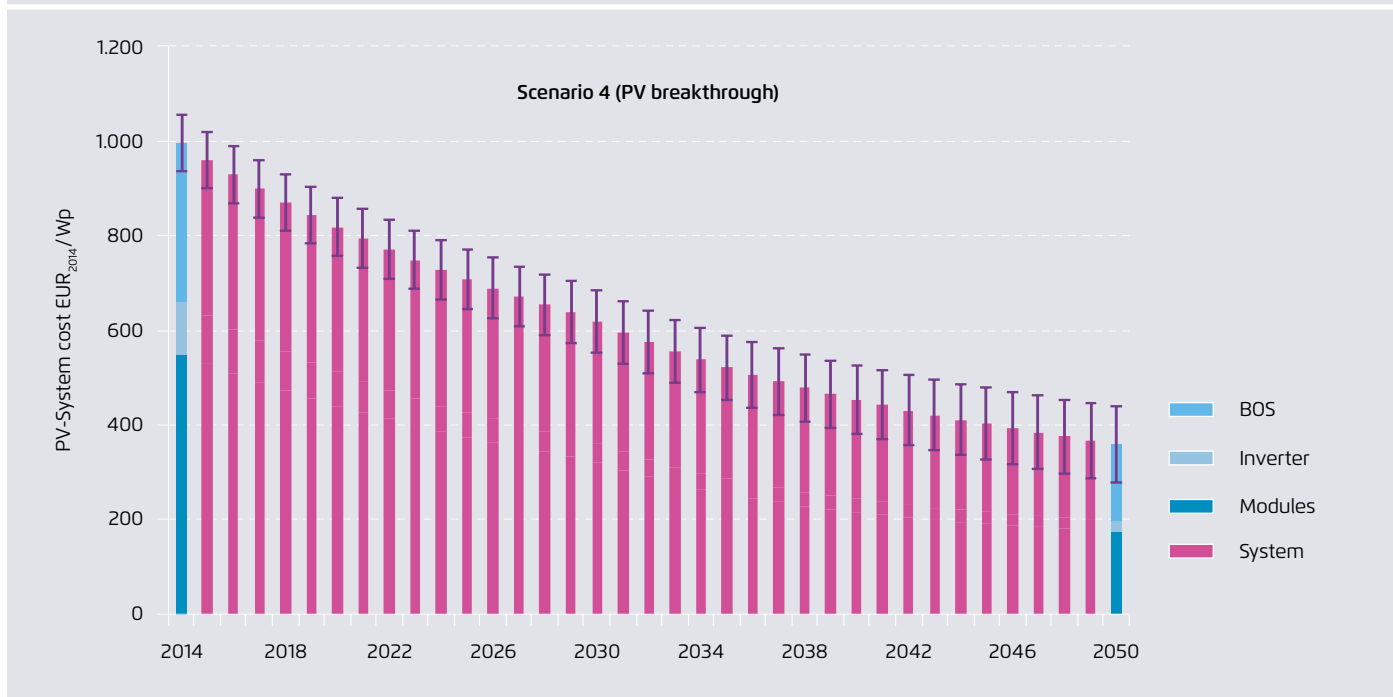
Own illustration

9.5 Detailed assumptions and results on BOS cost

Detailed assumptions on BOS cost reduction   Table 10

	Assumptions on BOS cost reduction			
	Cost 2014 (€/kWp)	Efficiency impact factor	Cost reduction (Min)	Cost reduction (Max)
Installation	50	100%	10%	40%
Mounting	75	100%	20%	50%
DC cabling	50	75%	10%	30%
Switch gear	5	0%	0%	50%
Grid connection	60	0%	40%	60%
Transformer	20	0%	20%	40%
Infrastructure	40	75%	10%	30%
Planning & doc.	35	75%	0%	30%

Detailed results on BOS cost in 2050   Table 11

Detailed results on BOS cost in 2050						
Cost reduction scenario Efficiency scenario	Best conserv.	Best medium	Best optimist.	Worst conserv.	Worst medium	Worst optimist.
Installation	28	23	19	19	15	13
Mounting	38	30	26	23	19	16
DC cabling	32	28	26	25	22	20
Switch gear	5	5	5	3	3	3
Grid connection	36	36	36	24	24	24
Transformer	16	16	16	12	12	12
Infrastructure	26	23	21	20	18	16
Planning & doc.	25	22	20	18	15	14
Total BOS	206	182	168	144	127	117

Detailed BOS cost results in 2050 depending on efficiency scenarios   Figure 72
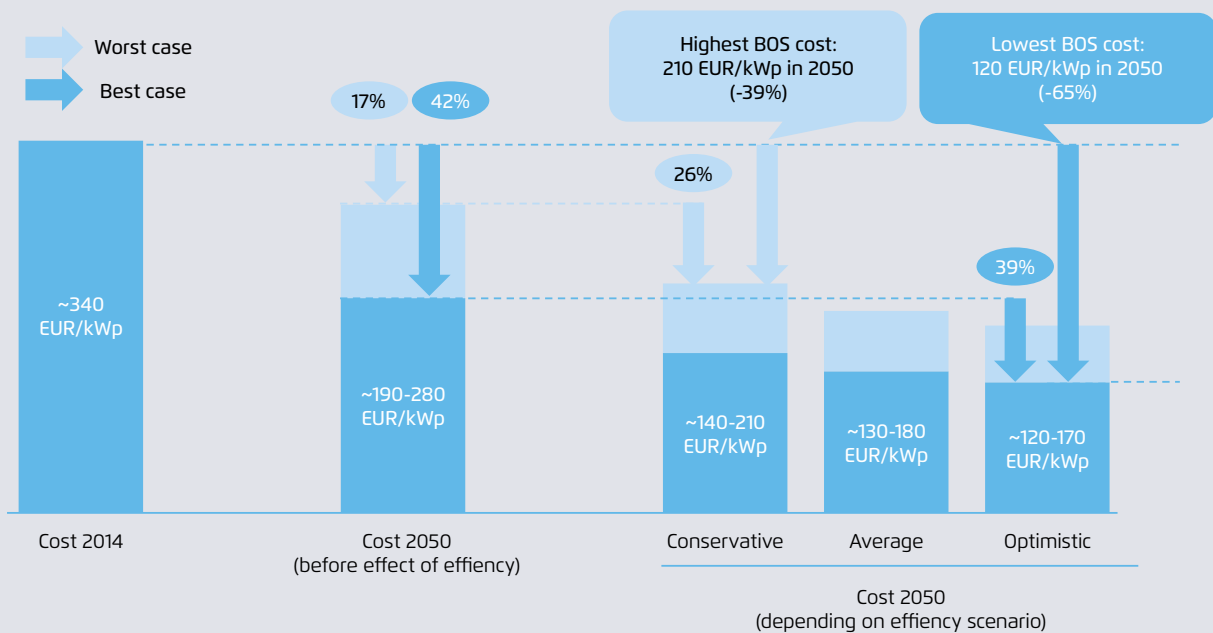
Own illustration

9.6 List of literature

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9.7 List of figures

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