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European PV Technology Platform Steering Committee
PV LCOE Working Group

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Disclaimer

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Background and definition of PV LCOE

The cost of photovoltaic (PV) electricity has decreased dramatically over the past years. Parity with retail electricity and oil-based fuels has been reached in many countries and market segments and wholesale parity is approaching in some markets. In order to make fair comparisons with electricity prices and the cost of other power generation technologies, the concept of Levelised Cost of Electricity (LCOE) is widely used. In this report, the LCOE is defined to be the average generation cost, i.e., including all the costs involved in supplying PV at the point of connection to the grid. Possible grid integration costs have been extensively studied, e.g., by the PV Parity project and shown to be in the order of 0.01-0.02 €/kWh for most European countries by 2030 (PV Parity, 2013). The PV LCOE is based on the PV system price and includes the costs and profit margins of the whole value chain including manufacturing, installation, project development, operation and maintenance (O&M) etc. It also includes the cost of financing but excludes the profit margin of electricity sales and thus represents the generation cost, not the electricity selling price which can vary depending on the market situation.

The PV LCOE, expressed in €/kWh in real money, can be defined by equation (1)

$$LCOE = \frac{CAPEX + \sum_{t=1}^{n}[OPEX(t)/(1+WACC_{Nom})^t]}{\sum_{t=1}^{n}[Utilisation_0 \cdot (1-Degradation)^t / (1+WACC_{Real})^t]}$$

where

- t = time (in years)
- n = economic lifetime of the system (in years)
- CAPEX = total investment expenditure of the system, made at t=0 (in €/kWp)
- OPEX(t) = operation and maintenance expenditure in year t (in €/kWp)
- $WACC_{Nom}$ = nominal weighted average cost of capital (per annum)
- $WACC_{Real}$ = real weighted average cost of capital (per annum)
- $Utilisation_0$ = initial annual utilisation in year 0 without degradation (in kWh/kWp)
- Degradation = annual degradation of the nominal power of the system (per annum)

and $WACC_{Real} = (1 + WACC_{Nom}) / (1 + Inflation) - 1$ (2)

where Inflation is the annual inflation rate.

Discounting the expenditures with nominal WACC and electricity generation with real WACC ensures that the net present value (NPV) for the investment with nominal WACC is zero when valuing the generated electricity for the real LCOE. An alternative method is to assume that the inflation rate is zero in the equation and to use real WACC for discounting both the expenditures and the generation. Both methods give the same value for LCOE.

Input data

WACC and inflation

The most important parameter affecting the PV LCOE is the Weighted Average Cost of Capital (WACC). It will be seen later in the results of this document that a difference of 8 percentage points in real WACC about doubles the PV LCOE. The reason is that most of the costs related to PV generation are paid up front, and therefore, WACC has a big influence. There are no fuel costs related to PV, and therefore, operational expenditure (OPEX) is usually relatively smaller compared with capital expenditure (CAPEX) over the lifetime of a PV system.

There are several sophisticated models for determining the WACC, for example, the so called CAPM model which takes into account e.g. risk free interest rates, country spreads and market premiums for the equity, cost of debt and corporate taxes. In simple terms, WACC is a weighted average of the cost of equity and cost of debt. For example, if the cost of debt is 2% and cost of equity 12%, and the share of equity would be 30% of the investment, then the WACC would be 5%.

Often, the WACC rates are given in nominal terms, i.e., in the nominal currency that includes the annual inflation. In order to be comparable with the current cost of living, all input data and results in this report are given in real 2014 currency, unless otherwise stated. This means that the inflation must be taken into account in the calculations, as is done in Eq. (2). Usually, nominal WACC increases with the inflation rate, and therefore, real WACC is a better indicator of the real cost of capital of the investment. As an example, the average annual inflation for Euro area during 2001-14 has been about 2%. Using this inflation rate, a 5% real WACC would translate to a nominal WACC of 7.1%.

WACC rates depend on the country, market segment, investor type and risk appetite, among other things. For example, private investors often have higher WACC rates than public investors, whereas industrial and utility-scale investors have higher WACCs than residential and commercial investors. The level of WACC depends very much on the alternative options for investments. It can be argued that the real WACC for a residential PV system can even be negative if the investment is done with own money and the alternative is keeping money in the bank with a low interest rate.

Because of the highly subjective nature of the WACC, several values for real WACCs are used in this report. Using real WACCs means that the inflation is set at zero in Eq. (2). The real WACC values used here are:

Residential system (5 kWp): 2% and 4%
Commercial system (50 kWp): 2%, 4%, and 6%
Utility-scale systems: (1 and 50 MWp) 2%, 5%, and 8%

CAPEX

The capital investment of a PV system can be divided into two components: the PV modules and the Balance of System (BoS). The BoS includes e.g. mounting structures, cabling, inverters, transformers and other electrical components, grid connection, infrastructure, installation work, planning, documentation and other work. CAPEX in this report is the all-inclusive turnkey PV system price that needs to be paid upfront. It is assumed here that the CAPEX is paid in full during the year of installation of the system and the system starts producing electricity from the next year.

PV modules

The price of PV modules has decreased dramatically over the past years. From 2008 to 2012, the average sales price of PV modules collapsed by almost 80%. One of the reasons behind this was the removal of the bottleneck in solar-grade silicon manufacturing and the subsequent decrease in silicon price. Moreover, with the increasing market volumes, the processes and use of materials in PV module manufacturing have become more efficient and further reduced the price. Temporarily, overcapacity in all along the value chain drove PV module prices even to the level of cash costs of manufacturing.

In a longer time perspective, the average PV module prices have followed closely the so-called learning curve which is familiar from other industries. It means that each time the global cumulatively produced volume has doubled, the average price has been reduced by a certain percentage. In the case of PV modules, the learning rate has been about 20%. International Energy Agency (IEA) Technology Roadmap for Solar Photovoltaic Energy (IEA, 2014), Fraunhofer ISE (2015) and SEMI International Technology Roadmap for Photovoltaic (ITRPV, 2015) report historical learning rates between 19% and 23%. The slight difference can be attributed to whether or not other than crystalline silicon (c-Si) modules are included in the average and to the start and end year of the learning curve.

Currently, the global market share of c-Si modules is more than 90% and the rest is thin film (CdTe, CIGS, or a/μc-Si). The market shares are not expected to change dramatically during the next ten years and even if they would, thin films would need to follow a learning curve which brings the prices to a competitive level with c-Si. For this reason, a learning rate of 20% is used for all PV modules in this report.

In order to establish the future price for PV modules according to the learning curve, a projection for global cumulative installation volumes is needed. As a starting point, the realised cumulative volume of 178 GWp at the end of 2014 is used (SolarPower Europe, 2015). As a base scenario, the IEA PV Technology Roadmap (IEA, 2014) projection is used. According to this scenario, the global cumulative capacity would be about 1720 GWp in 2030 which would mean a less than 100 GWp average annual capacity addition during 2015-2030, compared with the 2014 annual market of 40 GWp. Historically, the IEA projections have been quite conservative compared with realised market volumes. Other respected scenarios, such as from Bloomberg New Energy Finance and Greenpeace, have similar projected capacities for 2030 (about 1760 and 1860 GWp, respectively).

In order to get volume projections for the immediate future, SolarPower Europe (2015) Global Market Outlook for Solar Power 2015-19 medium scenario is used for 2015-19 for the base scenario. In the past (SolarPower Europe was previously known as EPIA), this scenario has been quite accurate with the true market growth. According to SolarPower Europe (2015), the cumulative capacity at the end of 2019 could be about 460 GWp. Interpolating from this to 1720 GWp in 2030 gives an average compound annual growth rate (CAGR) of about 10% for the annual installations. For the past decade, CAGR has been well above 40% on the average, which means that the industry could grow much faster if needed.

To make a sensitivity analysis, two other scenarios are presented. Slow growth scenario assumes SolarPower Europe (2015) low scenario until 2019 and annual market of 50 GWp after that, i.e., 0% CAGR from 2019 to 2030. Fast growth scenario assumes SolarPower Europe (2015) high scenario until 2019 and CAGR of 15% from 2019 to 2030. It can be seen that the difference of either of these extreme scenarios to the Base case is less than one doubling of the cumulative volume, meaning that the module price uncertainty from the volume is less than +/-20% by 2030. The different secenarios can be seen in Figure 1.

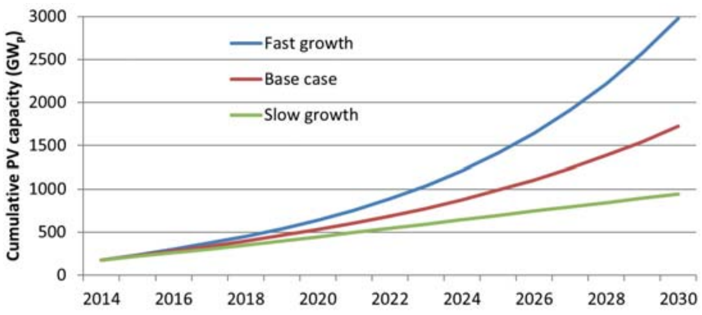

Figure 1. Global cumulative volume of PV installations 2014-30 according to the three scenarios

The volume growth and module prices have been observed starting from 1976. Most recently, the data has been collected by SPV Market Research (in US dollars). In order to start from a point where the actual price matched the average 20% learning curve, year 2003 has been selected as the starting point. Applying the 20% learning rate from 2003, the average PV module price for 2014 would be 0.705 $/Wp. Since the focus of this report is Europe, the LCOE calculations are presented in euros. Because of currency fluctuations, long-term average conversion rate should be used. In Figure 2, the value of 1 € in USD for 2004-2014 is shown. The average of the period, 1.33 USD/€, is used here. All prices given in this report are in 2014 currency.

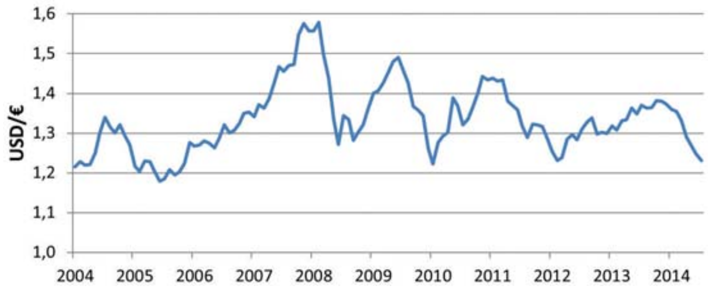

Figure 2. Value of 1 € in USD for 2004-2014

The value of euro in dollars has dropped dramatically since European Central Bank began quantitative easing in 2015. But the average for 2004-2014 is used in this report to demonstrate PV prices compared with other electricity prices which will all be impacted by the exchange rate. The volatility of the exchange rate is in fact included in the WACC estimation.

With the conversion rate of 1.33 USD/€, the 2014 module price would be 0.53 €/Wp. That was exactly the German pvXchange market price for the Chinese PV modules in December 2014. That was also the minimum price at that time set by EU Commission for the Chinese modules. It can be considered as the year 2014 end PV module price for 1 MWp ground-mounted systems in Europe. For residential and commercial rooftop systems, the module price at the end of year 2014 was estimated to be 15% higher, i.e. 0.61 €/Wp. That corresponded to about the year 2014 end pvXchange average price for the German, Japanese and Korean PV modules. For large (50 MWp) ground-mounted systems, the end of year 2014 module price was estimated to be 15% less, i.e. 0.45 €/Wp. That corresponded exactly to the December 2014 pvXchange price for other Southeast Asian PV modules. Figure 3 shows the PV module price development in the three different volume growth scenarios for a 1 MWp PV system.

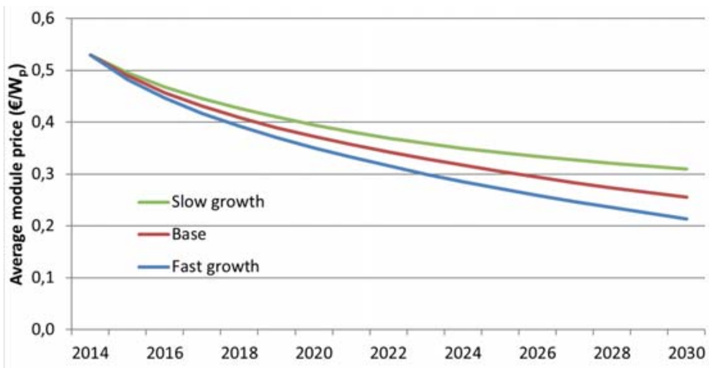

Figure 3. PV module price development 2014-30 for a 1 MWp ground-mounted system in the three different volume growth scenarios

Input data ● CAPEX

Balance of System components

Balance of System (BoS) components have become relatively more important because of the great reduction in the PV module prices. In most, especially smaller PV systems, BoS price is nowadays more than half of the total system CAPEX. Most BoS components, with the exception of the inverters, do not follow the same learning curve as the PV modules. Many components like cables and mounting structures represent conventional technology which does not have similar price reduction potential as silicon and other semiconductor devices. However, a large part of the price of the BoS components depend on the surface area of the system, and hence, the efficiency of the modules. As the efficiency of the PV modules increases, the required area per Wp of installed system capacity and the related BoS price of the system decreases.

During the past decade, the average efficiency of commercial c-Si PV modules has been increasing by about 0.4 percentage points per year (Fraunhofer ISE, 2014). For some thin film modules, the development has been even faster in recent years. In 2014, the average efficiency, covering all module types, was about 15% (Fraunhofer ISE, 2015). For single-junction c-Si cell, theoretical maximum is slightly less than 30%, and for a commercial single-junction c-Si module, about 25% because of practical reasons and inevitable losses in the module (Fraunhofer ISE, 2015).

Assuming that the 0.4 percentage point per year increase continues, the average PV module efficiency would be about 21.4% in 2030. This estimate is plausible since the best commercial c-Si modules (Sunpower X-series) in the market already have 21.5% efficiency. It is also possible that various silicon-based high-effciency cell technologies, like heterojunction n-type cells, become cost-competitive sooner than expected (ITRPV, 2015), and the average efficiency increases even faster. There is every reason to believe thet the average efficiency increase will continue during the coming decades. In this report, an average PV module efficiency increase of 0.4% percentage points per year is assumed for 2014-2030.

To get an overview of the BoS price reduction potential, it is possible to divide the BoS components into three main groups:

1. components following a learning curve (inverters)
2. components depending on the area of the array
3. other components depending on the power of the modules or having fixed costs

In reality, most of the components depend both on the power and area of the array. Table 1 lists the BoS components with the percentage of area-dependence and price in 2014, and area-related and other price reduction by 2030 for a 1 MWp ground-mounted system in Germany (Fraunhofer ISE, 2015). It must be noted that the prices could be even lower for a very efficient project in Germany. However, the prices could be higher in some places due to local conditions related to grid connection, labour costs or higher profit margins. Local BoS price differences are not taken into account in the Base case of this report but can be seen in the sensitivity analysis.

BoS component	€/kWp 2014	Area-related share 2014	€/kWp area-related 2014	€/kWp area-related reduction by 2030	Other reduction by 2030	€/kWp other reduction by 2030
Inverter	110	0 %	0	0	Learning curve	
Mounting structure	75	100 %	75	23	16 %	12
Installation work	50	100 %	50	15	11 %	6
DC cables	50	75 %	38	11	9 %	4
Grid connection	60	0 %	0	0	24 %	15
Infrastructure	40	75 %	30	9	9 %	4
Planning & docum.	35	75 %	26	8	7 %	2
Transformer	20	0 %	0	0	13 %	3
Switch gear	5	0 %	0	0	11 %	1
Total BoS	**445**	**49 %**	**219**	**66**	**10 %**	**45**

Table 1. BoS components, their price and area-dependence in 2014, and price reductions by 2030 for a 1 MWp ground-mounted PV system in Germany 2014 (Fraunhofer ISE, 2015)

It can be seen from Table 1 that weighted with the component prices, the share of area-dependence is currently about 50% of the total BoS price. Applying the 0.4 percentage point annual efficiency improvement would mean that the BoS price would decrease by 15% by 2030 because of the reduced PV system area alone.

The share of the inverter is about 25% of the total BoS price in Table 1. The inverter price shown here (0.11 €/Wp) represents the current spot market price in Germany for 10-100 kW string inverters. The price of small inverters has historically followed a learning curve with a 20% learning rate (Hoffmann, 2014). Large central inverters can be cheaper but do not necessarily follow the same learning curve. However, string inverters can also be used in large installations. Therefore, it is assumed here that the inverters will follow the same learning curve as the modules during 2014-2030, and the inverter price for a 1 MWp system in 2014 is the one shown in Table 1. This means that the inverter price will be about halved by 2030 and leads to a 12.5% reduction in BoS price.

In addition to the inverter learning curve and area-related effect, there will be other price reductions driven by, e.g, standardisation and modularisation, increase in DC voltage and more efficient installation processes. These were reported by Fraunhofer ISE (2015) until 2050, Table 1 shows interpolated reductions by 2030. It can be seen that the other reductions will be an average 10% compared with 2014 price. In total, BoS price reduction with the inverter (12.5%), area-dependence (15%) and for other reasons (10%) would more than 35% by 2030. Figure 4 shows total PV system CAPEX development for a 1 MWp ground-mounted system in Germany during 2014-30. It can be seen that total PV CAPEX will be reduced by more than 20% by 2020 and by about 45% by 2030.

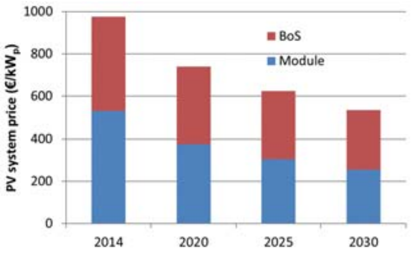

Figure 4. PV CAPEX development 2014-30 for a 1 MWp ground-mounted system in Germany

For the residential and commercial rooftop market segments, the BoS price is naturally higher. German Solar Energy Association (BSW-Solar) has been gathering PV system CAPEX prices for many years. According to BSW-Solar factsheet (April 2014), the average PV system price for residential rooftop systems (<10 kWp, without taxes) was 1.64 €/Wp in Q1/2014. Allowing for the module price reduction by about 0.05 €/Wp during 2014, the BoS price would have been 0.98 €/Wp with a module price of 0.61 €/Wp (see 2.2.1) for a residential system at the end of 2014 or about 120% higher than for a 1 MWp ground-mounted system. For commercial systems (10-100 kWp), BSW-Solar reported 1.32 €/Wp as the average system price (Fraunhofer ISE, 2014) with a 50% or 0.66 €/Wp share of BoS which would be about 50% higher than for a 1 MWp ground-mounted system.

For a large (50 MWp) utility-scale system, a 15% reduction for both modules and BoS is assumed. This reflects mainly the current market price in competitive markets like Germany. It must be noted that the PV system price varies between countries because of, e.g., extra permitting, grid connection or land costs. However, it is assumed that the prices will converge over time in Europe and therefore, only one price for each market segment is used here. It is assumed that for each year, the commercial rooftop system (50 kWp) will have 50% and residential system (5 kWp) 120% higher and large utility-scale system (50 MWp) 15% lower BoS price than a 1 MWp ground-mounted system. The effect of possible local price differences can be seen in the sensitivity analysis.

OPEX

The operational expenditure (OPEX) of PV systems consists mainly of the operation and maintenance (O&M) cost because there are no fuel costs related to PV electricity generation. The need for O&M can be very different depending on the system size and type. In many countries, residential PV systems need hardly any O&M because rain and snow will clean up the modules. Small inverters need usually no maintenance and are replaced at the end of their lifetime. Inverter replacement cost is not included in the O&M cost in this analysis but is taken into account as a separate CAPEX investment at the halfpoint of the system lifetime. Some systems may have insurance which can be around 0.5% of the system CAPEX annually. There may be some administrative or monitoring costs. 1% of the current residential system CAPEX (including 20% VAT) would result in an OPEX of 19 €/kWp/year.

In commercial rooftop systems, the OPEX is typically 1-2% of the CAPEX annually. 1.5% of the current commercial system CAPEX would result in an OPEX of 19 €/kWp/year. In commercial buildings of many installations, there are often electricians or other maintenance personnel for other purposes and the occasional maintenance for PV systems might not add much extra cost. For ground-mounted systems, there are clearly economies of scale, which means that some fixed costs result in reduced OPEX per unit when the system size increases. On the other hand, many maintenance costs are related to the area of the system and therefore, will reduce when the module efficiency improves.

Historical OPEX data from different countries vary greatly and it is difficult to find a consensus opinion. In the past, many European countries had a very high feed-in tariff (FIT) which allowed high margins in both the system CAPEX and OPEX; some reports have quoted very high OPEX prices. Over the years, the FITs have been reduced and even finished in many countries, which has increased the competition and reduced the price of OPEX. Figure 5 shows the 'Full Service' O&M contract price development in Italy in 2011-2013 according to Bloomberg New Energy Finance (BNEF, 2013). It shows that the average O&M price was reduced by almost 40% from 2011 to 2013.

During the past 18 months, the O&M price has continued to decrease, albeit more slowly. A private communication with BNEF (April 2015) revealed that the price at the start of 2015 was around 18 €/kWp/year. However, in some countries like Germany, much lower O&M prices (even 5-10 €/kWp/year) have been reported. All depends on the service required by the customer. The low prices do not usually include extraordinary maintenance on major equipment or extension of inverter warranty (the inverter replacement cost is taken into account separately in this report). In some countries, taxes, land lease or grid fees could add to the OPEX price. In Italy, theft attempts have been a problem, which has increased security costs.

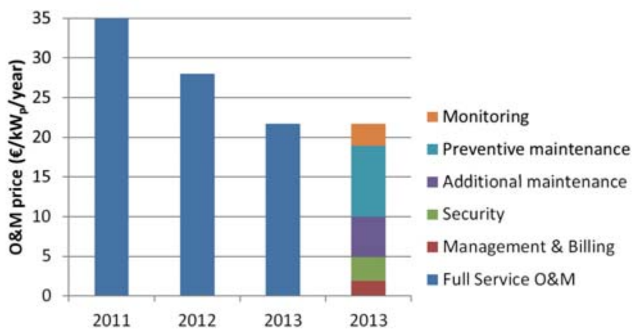

Figure 5. Development of 'Full Service' O&M contract price in Italy (Bloomberg New Energy Finance, 2013)

The need for O&M depends on the investor's willingness to carry risk, e.g., how much preventive maintenance is required. It should be analysed case by case, whether the added O&M cost adds value. In this report, the OPEX in 2014 is set to 20 €/kWp/year for residential, commercial and 1 MWp ground-mounted systems and 15 €/kWp/year for 50 MWp ground-mounted systems. It is assumed that 50% of the OPEX is area-dependent, and thus reducing with the efficiency improvement of the modules. By 2030, this will lead to a 15% reduction of the OPEX. It is also assumed that standardisation, more efficient processes and competition will result in a further 15% reduction of the OPEX by 2030 compared with 2014. Therefore, the overall OPEX would reduce by 30% by 2030, or to 14 €/kWp/year for other than the largest systems, and to 10.5 €/kWp/year for the 50 MWp systems.

It must be emphasised that there will be variation in the OPEX prices in different countries although the difference should reduce in the future. The figures given here represent an average typical efficient O&M process in Europe. The possible country differences will be seen in the sensitivity analysis. For example, there are communal taxes, extra security costs and grid feed-in tariffs in some locations, which are excluded in this analysis. Moreover, end-of-life plant dismantling costs are excluded. However, the dismantling cost would increase the LCOE by less than 2% or 1-2 €/MWh, depending on location, if a 10% increase in CAPEX with a 5% real WACC would be assumed at the end of the PV system lifetime.

Utilisation, degradation and system lifetime

Annual irradiation is one of the most important parameters affecting the PV LCOE, and it obviously depends on the location. A great majority of European population lives in an area where the average annual global horizontal irradiation (GHI) varies from about 950 kWh/m^2 in Stockholm (latitude 59°N), Sweden, to about 1840 kWh/m^2 in Malaga (latitude 37°N), Spain. To get a representative view of the varying irradiation conditions in different geographical areas in Europe, four other locations in addition to Stockholm and Malaga have been selected from the biggest EU countries: London, UK (GHI = 1000 kWh/m^2), Munich, Germany (GHI = 1150 kWh/m^2), Toulouse, France (GHI = 1360 kWh/m^2), and Rome, Italy (GHI = 1580 kWh/m^2). The irradiation values are given according to SolarGIS database averages for 1994-2014 (GeoModel Solar, 2015).

To evaluate the electricity yield a PV system generates at certain irradiation conditions, the concept of performance ratio (PR) is used. PR is defined as the ratio between the electricity actually generated by the PV system to the electricity an ideal lossless PV system would produce with the same amount of irradiation and at a module temperature of 25°C (IEA PVPS, 2014b). PR takes into account various losses by e.g. reflection, shadowing, temperature, low light levels, cables and inverters. A realistic initial PR for a ground-mounted PV system is about 0.80 for Southern Europe and about 0.825 for Central Europe (IEA PVPS, 2014b). The main reason for the difference is the negative temperature coefficient of the PV modules, which means that the average operating efficiency of modules is lower in warmer climates.

Another major difference is between ground-mounted and rooftop systems. Modules on rooftops are often ventilated less than free-standing ground-mounted modules, and are therefore at higher temperature. Rooftop systems are also smaller and have usually less efficient inverters. Another factor is that ground-mounted systems on open fields have usually less shadows from trees or buildings than rooftop systems in a built environment. On the other hand, module arrays in ground-mounted systems usually have a small shadowing effect on each other. Also, large ground-mounted systems tend to be situated at the best irradiation locations whereas rooftop systems are where people happen to live or have business. Overall, the difference in PR between small rooftop and large ground-mounted systems seems to be between 5 and 10 percentage points (IEA PVPS, 2014b). Therefore in this report, for Stockholm, London and Munich, PR is 0.825 for ground-mounted installations and 0.75 for rooftops. For Toulouse, Rome and Malaga, PR is 0.80 for ground and 0.725 for rooftops.

Table 2 shows in addition to GHI the irradiation for a surface tilted 30° towards South which gives almost the maximum annual yield for all locations. The annual utilisation or peak load hours are calculated for the tilted surface with the given performance ratios. It can be seen that even though Stockholm has 5% less GHI than London, the annual utilisation hours are exactly the same. This is mainly because the latitude and also the direct sunlight component in Stockholm is higher which gives more benefit when tilting the PV module surface towards South. Because London and Stockholm utilisation hours are the same and all other input data being the same, these locations have the same PV LCOE. Therefore, London and Stockholm are put together in the graphs of the Results section. It can also be noted that even at latitudes of 60-61° in Southern Finland, the annual utilisation hours would be similar to London and Stockholm.

	Irradiation (kWh/m^2)		Utilisation (h)	
	GHI	30° South tilt	Rooftop	Ground
Stockholm	950	1160	870	960
London	1000	1160	870	960
Munich	1150	1360	1020	1120
Toulouse	1360	1580	1150	1260
Rome	1580	1830	1330	1460
Malaga	1840	2100	1520	1680

Table 2. Annual GHI, irradiation on tilted surface, and utilisation for different locations (source for irradiation data: Geomodel Solar, 2015)

The annual utilisation hours in Table 2 are initial values, i.e., without any degradation. When c-Si modules are first put in sunlight, they may initially suffer a small light-induced degradation. For this initial degredation, a typical 1% reduction in utilisation is used in this report. The module output may further degrade gradually over time for several reasons related to module quality. Most manufacturers guarantee an output of 90% of the initial nominal output after 10 years and 80% after 25 years. These values, however, are extremely conservative and would mean an average 0.9% degradation per year. Most systems in Europe degrade far less and, e.g., an average degradation of 0.2% per year has been reported for German rooftop systems (Fritze et al., 2013). A conservative value of 0.5% per year is used here, based on the findings of IEA PVPS Task 13 recent report (IEA PVPS, 2014a). This would mean an average 7% reduction in the annual PV electricity generation over a 30 year lifetime of a PV system, compared without any degradation. However, it is likely that real degradation rates will reduce in the future as PV module technology and quality improves. For example, glass-glass modules seem to be very stable and are becoming increasingly common.

Clearly, system lifetime is related to the degradation of the system. Today's module concept has been introduced in the mid 1970s, thus a maximum lifetime of about 40 years can be recorded and several PV systems of the late 1970s and early 1980s have been measured in the last decade showing annual degradation of 0.3%- 0.5%. Therefore, a mid-term target of 50 years technical lifetime for high quality modules might be appropriate. However, since standard financial amortisation periods are much shorter, a PV system lifetime of 30 years is assumed in this report. This was also recommended by IEA PVPS Task 12 for life cycle assessment studies (IEA PVPS, 2014a) and reflects the quality of current PV systems, even though it is expected that the technical lifetime will increase in the future and give added financial and social benefits.

LCOE results

The LCOE of PV electricity generation is calculated for the six different locations and four market segments: residential (5 kWp) and commercial (50 kWp) rooftop and 1 MWp and 50 MWp ground-mounted systems.

Residential (5 kWp) rooftop PV LCOE

As can be seen from Figure 6, residential PV LCOE varies currently from about 75 €/MWh in Spain to about 135 €/MWh in the UK and Sweden with a 2% real WACC. This real WACC corresponds to about 4% nominal WACC if the inflation is 2%. With a 4% real WACC, the LCOE would currently be about 20-30 €/MWh higher. It must be noted that VAT is added to the CAPEX price in the residential segment. 2014 VAT rates were: Germany 19%, UK and France 20%, Spain 21% and Italy 10%. Sweden has a VAT of 25% but it was not calculated separately from the UK in the residential case, 22.5% was used for both. By 2030, the LCOE will decrease to about 45-80 €/MWh with a 2% real WACC, depending on the location. With a 4% real WACC, the LCOE in 2030 would be about 10-20 €/MWh higher than with 2% real WACC. Compared with current residential electricity retail prices (e.g., about 200 €/MWh in Sweden and 300 €/MWh in Germany, including taxes), PV LCOE is already cheaper in all six countries.

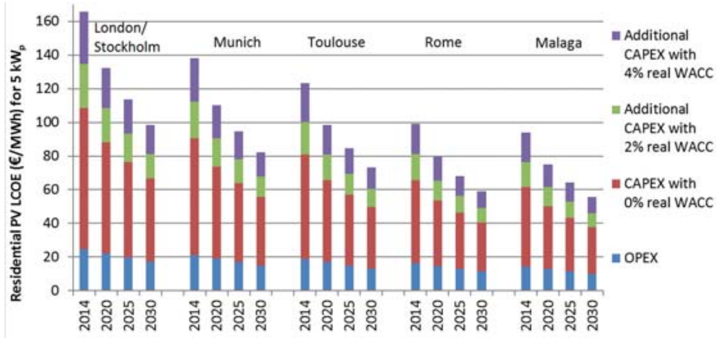

Figure 6. Residential (5 kWp) rooftop PV LCOE in 6 locations and with 2 different real WACCs

Commercial (50 kWp) rooftop PV LCOE

As can be seen from Figure 7, commercial PV LCOE varies currently from about 55 €/MWh in Spain to about 100 €/MWh in the UK and Sweden with a 2% real WACC. With a 4% real WACC, the LCOE would currently be about 10-20 €/MWh higher. VAT is not included in CAPEX or OPEX in commercial segment. By 2030, the LCOE will decrease to about 35-60 €/MWh with a 2% real WACC, depending on the location. With a 4% real WACC, the LCOE in 2030 would be about 5-10 €/MWh higher than with 2% real WACC. Compared with current commercial electricity retail prices, PV LCOE is already cheaper in all six countries.

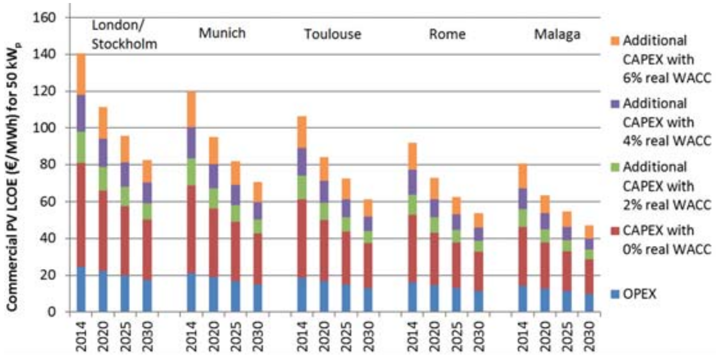

Figure 7. Commercial (50 kWp) rooftop PV LCOE in 6 locations and with 3 different real WACCs

Ground-mounted 1 MWp PV LCOE

Figure 8 shows the LCOE for a 1 MWp ground-mounted PV system in six locations and with three different real WACCs. It must be noted that 8% real WACC is extremely high and would represent a nominal WACC of 10.2% with a 2% annual inflation. This in turn would mean, e.g., an average cost of equity of 20% and cost of debt of 6% if the debt to equity ratio is 70/30. In some reports, even 10% interest rates have been reported which appear to be unrealistically high if considered as real WACCs.

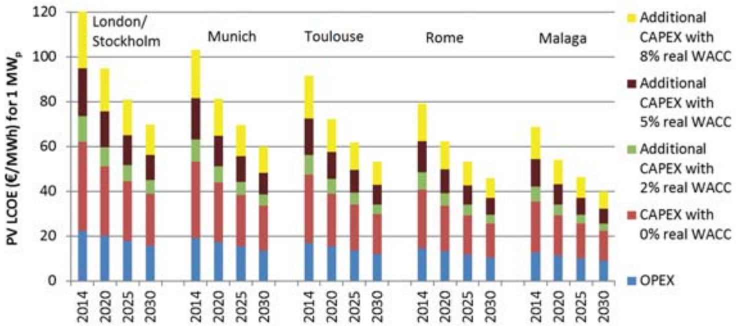

Figure 8. Ground-mounted 1 MWp PV LCOE in 6 locations and with 3 different real WACCs

As can be seen from Figure 8, PV LCOE for a ground-mounted 1 MWp system varies currently from about 55 €/MWh in Spain to about 95 €/MWh in the UK and Sweden with a 5% real WACC. With a 2%, real WACC, it would currently be about 10-20 €/MWh lower. By 2030, the LCOE will decrease to about 30-55 €/MWh with a 5% real WACC, depending on the location. With a 2% real WACC, the LCOE in 2030 would be about 5-10 €/MWh lower than with 5% real WACC.

Ground-mounted 50 MWp PV LCOE

To show how low the PV LCOE could actually go with large systems, the case for 50 MWp ground-mounted systems is presented in Figure 9. It must be noted that the size of very large PV systems elsewhere in the world has already reached 500 MWp and there is a clear benefit of scale when increasing the system size up from 1 MWp towards 1 GWp. It can be seen from Figure 9 that PV LCOE varies currently from about 45 €/MWh in Spain to about 80 €/MWh in the UK and Sweden with a 5% real WACC. With a 2%, real WACC, it would currently be about 10-20 €/MWh lower. This means that large-scale PV starts to already be competitive with wholesale electricity price in Southern Europe. In Italy, the average spot market electricity price in 2014 was 52 €/MWh. By 2030, the LCOE will decrease to about 25-45 €/MWh with a 5% real WACC, depending on the location. With a 2% real WACC, the LCOE in 2030 would be about 5-10 €/MWh lower than with 5% real WACC. By 2030, large-scale PV would be competitive with the current wholesale electricity price almost all over Europe.

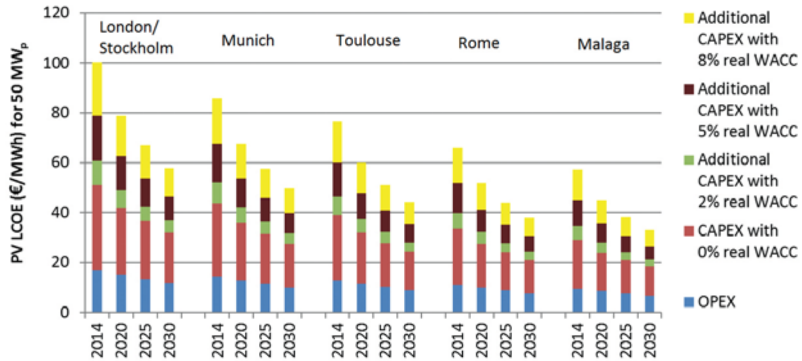

Figure 9. Ground-mounted 50 MWp PV LCOE in 6 locations and with 3 different real WACCs

Sensitivity analysis

The dependence of PV LCOE on the location and cost of capital was already shown in the results. The next most significant parameters influencing the LCOE are CAPEX and OPEX. The sensitivity analysis here is performed for a 1 MWp ground-mounted system in Toulouse.

Sensitivity on CAPEX

Figure 3 showed the development of PV module CAPEX in three different volume growth scenarios. These price projections are used directly for the 1 MWp ground-mounted system sensitivity analysis here. Of the BoS components, inverter price is supposed to follow the same learning curve as the PV module price. The area-related share of the BoS cost is currently same in all scenarios and is supposed to decrease according to the average annual 0.4%-point increase of the PV modules. This is a plausible assumption since it would lead to a 21.4% average module efficiency in 2030, which has already been surpassed by the best commercial c-Si PV modules in 2014. For the rest of the BoS, i.e., the non-inverter and not area-related component, a 20% decrease (instead of 10% in the base case) by 2030 is assumed for the fast growth scenario. For the slow growth scenario, this BoS component is assumed to remain at the 2014 price level. Table 3 summarises the CAPEX data used for the sensitivity analysis.

€/kWp	Fast growth			Base case			Slow growth		
	Module	BoS	Total	Module	BoS	Total	Module	BOS	Total
2014	530	445	975	530	445	975	530	445	975
2020	350	345	695	375	365	740	395	385	780
2025	270	280	550	305	320	625	340	355	695
2030	215	225	440	255	280	535	310	335	645

Table 3. PV module, BoS and total CAPEX for the 3 different scenarios for the 1 MWp system

It must be emphasized that the scenarios presented here do not require any technological breakthroughs, they are simply based on continued development of technology and manufacturing processes. It can be noted that most of the PV module price reduction of about 40% by 2030 in the slow growth scenario can be achieved with the efficiency improvement alone. Efficiency increase will be the most important driver towards lower PV LCOE in the future but there are others, notably material savings and manufacturing process development.

For example, silicon raw material can be saved by sawing thinner wafers or reducing the kerf (sawing) loss. Average wafer thickness is expected to be reduced from about 180 to 120 µm in 10 years and the cost of crystallisation and wafering is going to be reduced during the same time period, according to SEMI International Technology Roadmap for Photovoltaic (ITRPV, 2015). Moreover, the cost of solar-grade silicon is going to be significantly reduced by the introduction of fluidised-bed reactors. In cell metallisation, the amount of expensive silver is decreasing all the time and could eventually be replaced by copper. Further material savings are foreseen by, e.g., innovative handling, new interconnection and module encapsulation technologies and glass thickness reduction (ITRPV, 2015).

In manufacturing processes, development is expected, e.g., from larger silicon ingots, higher throughput of tools like diamond wire sawing, module lamination and stringing, and larger modules. According to SEMI ITRPV (2015), cost of PV modules could be reduced by about 50% from 2013 to 2024, which would be well in line with the fast growth scenario used here.

Figure 10 shows the PV LCOE for a 1 MWp ground-mounted system in Toulouse for the three different scenarios. It can be seen that the difference of fast and slow scenarios to the base case is less than +/-15% in 2030 with a 5% real WACC, i.e., about 5 €/MWh. For the other locations the difference would relatively be about the same. For the residential and commercial market segments, the relative difference would be slightly less but absolutely more.

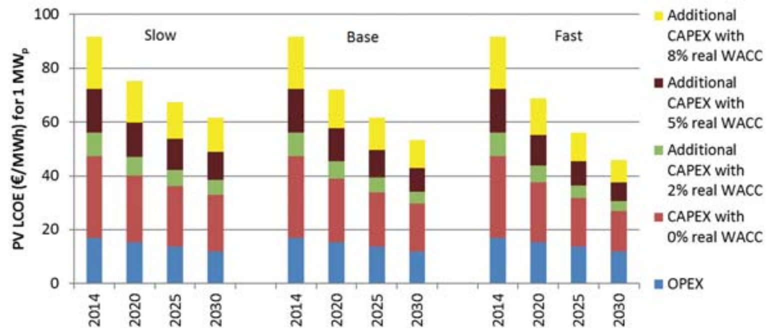

Figure 10. PV LCOE for a 1 MWp ground-mounted system in Toulouse in 3 different scenarios

Another source of uncertainty regarding the CAPEX is of course the learning rate. If a learning rate of 24% with base volume growth were used, the module price would be exactly the same in 2030 as with the fast volume growth and a 20% learning rate. Using 16% learning rate instead of 20% would give a slightly lower module price in 2030 than the slow growth case with a 20% learning rate, i.e., the CAPEX would change less. It can be concluded that changes in both volume growth and learning rate have relatively small effect (+/- 10-15%) on LCOE. The cost of capital (WACC percentage) is by far a more significant factor in PV LCOE than the CAPEX itself.

Sensitivity on OPEX

The share of OPEX of the PV LCOE depends heavily on the real WACC used. For a 2% real WACC, the OPEX share in the base case ranges currently from about 20% in residential rooftop segment to about 30% in ground-mounted systems and it is going to increase by a few percentage points by 2030. As was discussed earlier, the level of OPEX is difficult to determine and seems to vary a lot by case and location. In this sensitivity analysis, a lower value of 10 €/kWp/year (instead of 20 €/kWp/year) and a higher value of 30 €/kWp/year are used for 2014. The lower value represents many residential and efficiently operated larger systems, whereas the higher value may currently be true in some cases where full service with extended warranties is requested. In all scenarios, it is assumed that OPEX will decrease by 30% (mainly through PV module efficiency increase) linearly by 2030 which gives 7, 14, and 21 €/kWp/year respectively for the low, base and high OPEX cases in 2030.

Figure 11 gives the PV LCOE for a 1 MWp ground-mounted system in Toulouse in the three different OPEX scenarios. It can be seen that the difference of low and high scenarios to the base case is about +/-15% in 2030 with a 5% real WACC, or about 6 €/MWh. For rooftop market segments, the difference would be relatively less. In different locations, the situation does not change much. It can be concluded that the uncertainty in OPEX is at least as significant as in CAPEX, especially if the real WACC is low. With the high OPEX scenario and 2% real WACC, the OPEX share of the PV system lifetime LCOE would be about 45% in 2030. This leads to the conclusion that in the future, it is even more important to optimise operation and maintenance procedures in order to get value for the investment.

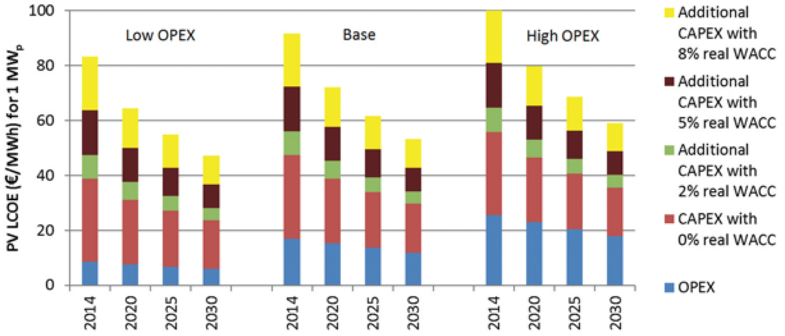

Figure 11. PV LCOE for a 1 MWp ground-mounted system in Toulouse in 3 different OPEX scenarios

Other sensitivities and summary

Other parameters having minor effect on the PV LCOE include module degradation and system lifetime. Using 0.8% annual degradation instead of 0.5% would lead to an average generation loss of about 11% during a 30 year system lifetime instead of the 7% with 0.5% degradation. Using 0.2% degradation would give about 3% generation loss. The effect on PV LCOE would be about +/-4% compared with 0.5% degradation.

The effect of system lifetime depends also on the real WACC: higher WACC leads to a smaller effect. Using 25 years instead of 30 years would increase the PV LCOE by about 10% with a 2% real WACC and by about 7% with a 5% real WACC for a 1 MWp ground-mounted system in Toulouse. Using 35 years would lead to a slightly smaller decrease in the PV LCOE.

In Figure 12, the sensitivity on various input parameters is summarised. The comparison is made for 2030 with the base case of 1 MWp ground-mounted system in Toulouse with a 5% real WACC and the parameters are in the order of significance. Obviously, the market segment with a specific system size is most important. But it can be noted that cost of capital (real WACC) is almost as important as location of the system is with its specific annual utilisation. OPEX and CAPEX are relatively less important than real WACC and utilisation whereas system lifetime and module degradation have only a minor effect on the PV LCOE. It must be emphasised that minimising cost of capital will be the single most important task in the future in order to drive down the cost of PV electricity generation.

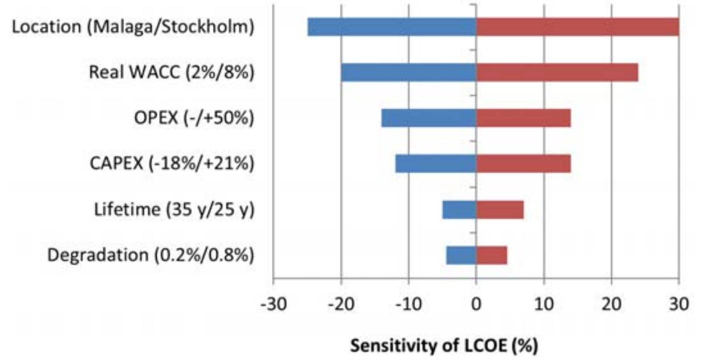

Figure 12. Sensitivity of PV LCOE in 2030 on location, real WACC, OPEX, CAPEX, system lifetime and degradation compared with a 1 MWp ground-mounted system in Toulouse with 5% real WACC, base CAPEX and OPEX, 30 years lifetime and 0.5% annual degradation

Discussion and conclusions

It has been shown that the PV module price will most likely to be halved again and BoS price will decrease by more than 35% by 2030, leading to an overall PV system CAPEX reduction of about 45%. It must be noted that this development does not require any major technology breakthroughs but is a natural cause from continuing efforts in reducing materials use, impoving efficiency and developing manufacturing processes. At the same time, PV system OPEX is expected to decrease by 30%. PV LCOE will decrease by 30-50% from 2014 to 2030, depending on the volume growth and learning rate. Cost of capital is by far more significant than CAPEX or OPEX: a 8% percentage point increase in real WACC will double the LCOE. It is the most urgent task for the solar industry to improve the bankability of PV, but at the same time for the policy makers to create a stable environment for investments, in order to decrease the cost of capital and thus the LCOE of PV.

Residential and commercial PV electricity is already competitive with retail market electricity in all selected countries. Parity with wholesale market electricity will be reached by 2030 almost everywhere. There is every reason to believe that this development will continue after 2030 because there is still a huge improvement potential in various PV technologies. Figure 13 gives the PV LCOE for a 1 MWp ground-mounted system until 2050 assuming that the annual market would stay at the 200 GWp level, learning rate at 20%, and module efficiency improves 0.4 percentage points per year from 2030 to 2050. This would mean that global cumulative PV capacity would be 5700 GWp in 2050 and average module efficiency about 30%. PV system price would decrease to about third from 2014 and OPEX is assumed to be halved. It can be seen that in Spain the LCOE in 2050 would be about 20 €/MWh and in the UK and Sweden below 40 €/MWh with a 5% real WACC, or about 60% less in 2050 compared with 2014. It can be concluded that PV will probably be the cheapest form of electricity generation in most countries in the coming decades.

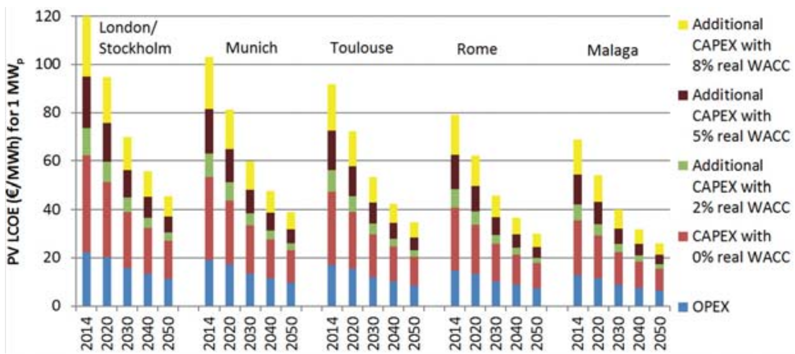

Figure 13. Ground-mounted 1 MWp PV LCOE in 6 locations and with 3 different real WACCs until 2050

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